COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

FITCHBURG GAS & ELECTRIC LIGHT COMPANY	)	**D.T.E. 02-24/25**

INITIAL BRIEF OF THE ATTORNEY GENERAL

Respectfully submitted,

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I. OVERVIEW

In these dockets, Fitchburg Gas and Electric Light Company ("Fitchburg" or "Company") seeks an extraordinary increase in its base rate revenues – 48.5% for its gas division ($3,413,357) and 24 % for its electric division ($3,206,768). Company management has done little to deserve such large increases. To the contrary, the Company since restructuring has failed to act as a responsible corporate citizen, as it committed repeated material accounting errors in its regulatory books that the Department of Telecommunications and Energy ("Department"), by order, or outside accountants have had to correct.

- In 1999, the Department determined that Company had failed to reflect load growth in the Seabrook amortization charge. D.T.E. 97-115.
- In 1999, the Department also questioned whether the Company in its Transition Charge Reconciliation properly reflected state income taxes related to the Seabrook amortization charge and ordered an audit. D.T.E. 97-115.
- In 2001, Arthur Andersen found that the Company had failed to properly recognize the state tax savings attributable to the Seabrook abandonment.
- In 2001, the Department also determined that the Company had double collected its gas inventory finance charges for over a decade. D.T.E. 99-66.

The Company's filings in this case were deficient in many respects. The Company failed to follow a number of specific Department directives and precedents, as discussed, *infra*.

The Company filed these two rates cases only six months after the Department determined that Fitchburg's electric distribution rates were "neither just nor reasonable" and ordered Fitchburg to reduce its electric rates by 8 %. D.T.E. 99-118. Given such timing, the Company's request here for a substantial electric base rate increase seems more in the nature of a request for reconsideration of the Department's rate reduction order, while consuming far more resources of the Department and the Attorney General than would such a motion appropriately filed in DTE 99-118.

Given this behavior, the Department should not reward the Company by granting large base rate increases. Instead, the Department should set the Company's rate of return at the lower end of the reasonable range and reduce the increase to base rate revenues as recommended by the Attorney General.

II. INTRODUCTION

The Attorney General submits this Initial Brief to the Department to address Fitchburg's petitions (collectively, the "Filing" or "Petition"). The increase requested by the Company is excessive, unwarranted and not supported by the evidentiary record before the Department.[1]

As is customary in this type of proceeding, the Attorney General will provide his final recommendations concerning the Company's revenue requirements in schedules attached to the Reply Brief.

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[1] The Company filed adjustments increasing the amount of its proposed base rate increases both at the beginning and during the evidentiary hearings, Tr. 1, p.18; RR-DTE 6, and indicated it intends to file additional amendments to its cost of service schedules after hearings. Tr. 15, pp.1886-1887. The Attorney General reserves his right to object to any late-filed adjustments.

A. Statement of the Case

On May 17, 2002, Fitchburg Gas and Electric Light Company ("Fitchburg" or the "Company") filed tariffs with the Department seeking a general increase in rates for both its gas and electric divisions. On May 22, 2002, the Department suspended the effective date of the rate increase until December 3, 2002, and opened an investigation into the propriety of the Company's requested rate increase.[2] On June 20, 2002, the Department conducted a public hearing at the Fitchburg Public Library Auditorium.[3] On June 21, 2002, the Department conducted a procedural conference and then issued a procedural schedule.[4] The Department held fifteen days of evidentiary hearings, between August 5 and 23 and September 4 and 10, 2002. During the evidentiary hearings, the Company presented the testimony of affiliate employees Mark H. Collin on revenue requirements and Karen Asbury on rate design, and outside consultants James H. Aikman on depreciation, James L. Harrison on cost allocation and related topics, and Samuel C. Hadaway on cost of capital.[5]

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[2] The test year is the twelve month period from January 1, 2001 to December 31, 2001.

[3] The Attorney General delivered a statement at the public hearing.

[4] The Attorney General and the Division of Energy Resources filed a Joint Motion seeking approval of a proposed procedural schedule that provided for a traditional seven-week briefing schedule that would allow intervenors the typical three weeks from the close of hearings to file initial briefs. The Hearing Officers issued a procedural schedule providing intervenors a mere two weeks to file initial briefs. The Attorney General appealed the procedural schedule ruling to the Commission on June 26, 2002, and renewed his request for relief on both the first (August 5) and last (September 10) days of hearings. To date, the Attorney General has received no ruling from the Commission on his appeal.

[5] Mr. Aikman and Mr. Harrision are management consultants with Management Applications Consulting, Inc.; Mr. Hadaway is a consultant with FINANCO, Inc.

B. Description of the Company

Fitchburg is a utility operating company that is wholly owned by Unitil Corporation ("Unitil"). Exh. FGE-MHC-1(Electric); Exh. FGE-MHC-1 (Gas). Fitchburg operates as a combined gas and electric distribution company and provides natural gas and electric distribution services to approximately 42,000 residential and business customers in north-central Massachusetts in the communities of Ashby, Fitchburg, Gardner, Lunenburg, Townsend and Westminister. *Id.* These communities have a total population of approximately 90,000 residents. *Id*. Fitchburg directly employs approximately 85 employees.[6] Exh. AG-1-44, Attachment 1. In addition to its regulated business, Fitchburg operates unregulated water heater and conversion burner rental programs. Exh. FGE-MHC-1(Electric); Exh. FGE-MHC-1 (Gas).

Fitchburg's electric division provides electric distribution service to approximately 27,000 customers in the communities of Fitchburg, Townsend, Lunenburg and Ashby. Exh. FGE-MHC-1(Electric). Fitchburg's electric division generates total operating revenues of $68,465,093, of which $14,152,520 are internal transmission and distribution ("T&D") revenues. Exh. FGE-MHC-1(Electric), Schedule MHC-1, MHC-2, MHC-3. Fitchburg's gas division provides distribution services to approximately 15,000 customers in the communities of Fitchburg, Townsend, Lunenburg, Ashby, Westminister and Gardner. Exh. FGE-MHC-1(Gas). Fitchburg's gas division generates total operating revenues in the amount of $22,827,857, of which $7,040,226 are of distribution revenues. Exh. FGE-MHC-1(Gas), Schedule MHC-1, MHC-2.

[6] Fitchburg is also assigned a portion of the employee costs of an affiliate, Unitil Service Corporation ("USC"), for shared personnel services USC provides. USC employs approximately 155 employees. Exh. AG-1-44, Attachment 1.

Fitchburg has various regulated and non-regulated affiliates. Fitchburg's parent company, Unitil, is a public utility holding company formed in 1984 when Concord Electric Company ("CECo") and Exeter and Hampton Electric Company ("E&H") merged. Exh. FGE-MHC-1(Electric); Exh. FGE-MHC-1 (Gas). CECo and E&H are regulated New Hampshire distribution companies that provide electric distribution services to approximately 71,000 customers. *Id*. CECo and E&H obtain all their power needs from another Unitil subsidiary, Unitil Power Corp., which is a FERC-regulated wholesale power supply company that supplies only CECo and E&H in New Hampshire. Unitil conducts its principal business of retail sale and distribution of gas and electricity in New Hampshire and Massachusetts through its three affiliated utility subsidiaries, Fitchburg, CECo, and E&H. *Id*.

Fitchburg's non-regulated affiliates (other than its parent) include Unitil Resources, Inc.,[7] a gas and electric brokering company; Unitil Realty Corp., which manages all properties held by the affiliates; and Unitil Service Company ("USC"), a centralized shared services company which performs shared utility services[8] for the affiliates and charges them for the services rendered.

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[7] Usource LLC is a subsidiary of Usource Inc. which is a subsidiary of Unitil Resources.

[8] USC performs: (1) Corporate and Administration; (2) Customer Service; (3) Energy Services; (4) Engineering and Operations; (5) Regulatory, Finance and Accounting; and (6) Technology.

III. RATE BASE

The Department should make several adjustments to the Company's rate base.

A. The Department Should Credit The Princeton Paper Equipment Deposit From The Bankruptcy Settlement Against Rate Base.

The Company has received several hundred thousand dollars in equipment deposits related to the Energy Bank contract for electric service to Princeton Paper which the Department should now order that the Company credit against electric rate base. As noted by the Company in its initial filing and in DTE 99-118, Princeton Paper filed for bankruptcy and no longer receives service. Exh. FGE-MHC-1 (Electric), p. 20. DTE 99-118, pp. 14-18. In the Attorney General's rate complaint case, the Company prevailed in removing all of the Princeton income from gross revenues. DTE 99-118, pp. 14-18. When directly questioned about Princeton's bankruptcy proceedings in DTE 99-118, however, the Company failed to disclose that it had filed a claim for over $6 million related to the Energy Bank contract and that the bankruptcy court had approved a settlement valued at over $3 million and allowed the Company to retain $893,495 in equipment deposits given to its electric division. Tr. 1, pp. 36 - 45; AG Exh. 2, pp. 13, 43.[9]

For purposes of the bankruptcy claim, the Company sought to keep the electric equipment deposit as compensation for outstanding gas and electric bills and for legal fees incurred. Tr. 11, pp. 1309-1312. The Company admitted on cross examination that it never submitted the bankruptcy settlement to the Department for approval, and that the actions of the

[9] The Company's witness had actually signed the multimillion dollar claim as Treasurer of Fitchburg, and the Attorney General has no explanation for the witness' lack of candor on this topic. Moreover, the same law firm represented the Company in the bankruptcy proceeding and before the Department in DTE 99-118 and the rate cases now under review.

bankruptcy court do not bind the Department for purposes of ratemaking purposes. Tr. 11, pp. 1312-1314.

The Department should order the Company to credit the retained deposit for equipment against electric rate base to prevent the Company from profiting from a windfall at the expense of customers. The deposit was required as a condition of service under the contract with Princeton to guarantee recovery of the costs of plant additions made by Fitchburg to connect the customer. Those plant additions are currently in rate base and are being recovered from other customers through their base rates. It is only fair and equitable that the proceeds from the bankruptcy in the form of the deposit be put towards that plant in service to reduce that investment. Therefore, the Department should order the Company to credit to the proceeds from the settlement to plant in service and reduce the Company's proposed rate base accordingly.

B. The Old Sawyer Passway Substation Is No Longer Used and Useful In Serving Customers And The Department Should Order That It Be Removed From Rate Base.

The Company proposes an extraordinary addition to its electric division rate base of $5,240,735, or 12.5%, the new Sawyer Passway Substation.[10] Company witness Mark Collin testified that this project is the largest single distribution project in the Company's history. He explained that the project:

> involved essentially the replacement of an early, or mid . . .1930's, 1940's vintage substation that was out on the site and had been in use a number of years. We essentially removed all the equipment from the old substation and built a new substation from the ground up.

Tr. 12, p. 1421.

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[10] The 12.5% is the total project cost of $5,240,735 divided by the rate base of $41,919,237. DTE RR-2; Sch. MHC-4(electric).

Mr. Collin testified that he believed that the new Sawyer Passway Substation went into service at "the beginning of 2000," and the old substation ceased serving customers "[b]asically the same time as the new substation turned over, so it was a simultaneous switch." Tr. 12, p. 1426. After the hearings, Mr. Collin indicated in a record response that the new Sawyer Passway Substation "initially went into service in late 2000 and became fully operational in June 2001," and the old substation "was taken off line on January 22, 2002." AG-RR-52 (electric). He stated that there:

> was not a simultaneous switch from old substation to new, because during 2001, new and replacement circuits were constructed to the new substation. This construction had to be completed before cutover and prior to de-energizing the old substation.

Id.

The Company proposes to include in plant-in-service not only the $5.2 million costs for the new Sawyer Passway Substation, but also over $1 million for the old substation that it replaced, even though the Company admits that the old substation is no longer serving customers. Tr. 12, p. 1426-7; AG-RR-52. The Company proposes to remove the old substation from rate base only when it is physically removed, during 2002 and early 2003. AG-RR-52.

The Company's proposed inclusion of the old substation in rate base would be neither fair to ratepayers nor consistent with Department precedent. *See, Fitchburg Gas and Electric Light Company*, D.P.U. 18296/18297(1975); *Fitchburg Gas and Electric Light Company*, D.P.U. 19084 (1978).[11] It would not be fair to charge ratepayers going forward the costs of both the very expensive new substation project and the old substation that it replaced. In the Company's last gas division rate case order, the Department stated that it:

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[11] The Supreme Judicial Court has upheld on appeal the Department 's authority to exclude from rate base the unamortized balance of abandoned plant, even where the original investment was prudent. *Fitchburg Gas and Electric Light Company v. Department of Public Utilities*, 371 Mass. 881, 886-887 (1977).

> determines rate base according to the cost of the utility's plant in service as of the end of the test year **under a used and useful standard**. D.P.U. 96-50 (Phase I) at 15. **In order to qualify for inclusion in rates, a utility's plant investment must be in service and providing benefits to customers**.

(emphasis added). *Fitchburg Gas and Electric Light Company*, D.T.E. 98-51 (1998). Since, according to the Company, the new substation was "fully operational" in June 2001, at least six months before the end of the test year, and the old substation was finally taken off line less than a month after the end of the test year, the old substation was used and useful only marginally, if at all, at test year end.

Old plant that was replaced and ceased operating less than a month after the end of the test year should clearly be removed from rate base under Department precedent. The Department has eliminated old plant from rate base even where the old plant had not yet been replaced, where the replacement was expected during the rate year. *Western Massachusetts Electric Company*, D.P.U. 85-270, pp. 140-141 (1985).[12]

The Department, therefore, should reduce the Company's cost of service to reflect the removal of the old substation, by reducing rate base by $1,033,889, increasing accumulated depreciation by $639,216 and reducing test year depreciation expense by $61,516. AG-RR-52.

C. The Company Overstates Its Cash Working Capital Needs.

The Department recognizes that there typically will be a difference in time between when a utility incurs costs to provide service to customers and the time when the utility collects cash from customers in payment for those services. *See* e.g. D.T.E. 99-118 and D.T.E. 98-51, pp. 14-

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[12] In that case, the Department removed three fossil-fuel generating units from rate base where those units would no longer be useful because of the addition of Millstone 3. For a similar result, *see Berkshire Gas Company*, D.T.E. 01-56, pp. 42-43 (2002).

15. If the expenses are incurred, and paid, prior to the time that payment is received from customers, this "lag" in receipt of payment creates a need for investor-supplied capital. *Id.* This need for capital is commonly referred to as the utility company's cash working capital requirement. *Id.* If cash is received, on balance, from customers prior to the time that disbursements are made in payment of expenses, the cash working capital requirement is negative. The amount that is actually included in rate base is the cash working capital allowance. This allowance can be based either on a detailed study of the actual cash working capital requirement, a "lead-lag study", or can be based on an arbitrary formula, such as a fraction of the utility company's expenses.

In the present case, Fitchburg has calculated its cash working capital allowance non-energy related operations and maintenance expense based on 1/8 of annual operation and maintenance expense, equivalent to approximately 45 days of expenses. Exh. FGE-MHC-1, Sch. MHC-4-1 (electric) and (gas). This arbitrary formula implicitly assumes that there is a 45 day lag between the time that a utility company pays for expenses that it has incurred and the time that it receives cash from customers to pay for those expenses. However, Fitchburg has offered no substantive defense of its use of the 45-day convention, only noting that the Department has not yet done away with this convention. Exh. FG&E-2, p. 21.

1. The Company Failed To Perform A Lead / Lag Study For Other Operations and Maintenance Expenses As Ordered By The Department.

The Department previously directed that the Company seek and consider cost-effective alternatives that produce lower working capital requirements than the 45-day convention. *Fitchburg Gas & Electric*, D.T.E. 98-51, p. 16 (1998); *Fitchburg Gas & Electric*, D.T.E. 99-118, p. 30, n.23 (2001). Despite this directive, the Company has chosen to retain the high working capital requirements of the 45-day convention, claiming that a lead/lag study would not be cost-justified. Exh. FGE-MHC-1 (Electric), p. 29. Since the Company has neither followed the Department order nor provided the basic record evidence necessary to support Fitchburg's request, the Department should deny the Company recovery of any cash working capital for its non-energy supply O&M expenses for both the electric and gas divisions. *Fitchburg Gas and Electric Light Company*, D.T.E. 98-51, p. 16 (1998).

2. The Company's Cost / Benefit Analysis For The Lead / Lag Study Shows There Is A Probability That The Study Would Result In Savings To Customers

The Company performed a cost / benefit analysis in an attempt to avoid having to perform the lead / lag study for its operations and maintenance expenses that was ordered by the Department. Exh. DTE2-38, DTE - RR-12. It claimed that the analysis was based on a comparison of the annual cost to customers of the study versus the potential benefit of a reduction in its cash working capital allowance as a result of a decrease in the net number of lead / lag days. *Id.*

There are many flaws in this analysis, however, that when corrected, indicate that there would probably be a net benefit to the study even at the highest of the claimed costs. First, the Company failed to perform the cost / benefit analysis from the customers' point of view. Rather, than consider the customers' actual cash cost through their rates over the recovery period, Mr. Collin chose to use some future value of that amount, thus inflating his estimate of the costs to customers. Tr. 15, pp. 1904-07. Second, Mr. Collin assumed that costs would be recovered over a seven year period, the average period between base rate cases. *Id.* This correction to the cost benefit analysis alone makes it likely that the study will be beneficial at the 49% probability level for the $193,000 proposal and at the 63% probability level for the $60,000 proposal. However, even that probability is understated in this case, since the Company's rate case costs, including the costs of the cash working capital study, should be recovered over, not seven years, but the 10-year term of the Company's proposed price cap plan if that is adopted by the Department. See *Berkshire Gas Company*, D.T.E. 01-56, p. 77 (2002) and *Boston Gas Company*, D.P.U. 96-50 (Phase I), p. 78 (1996). This will increase the probability of cost savings to customers even more. The Department should find that cost savings for customers are likely to be achieved through a cash working capital lead / lag study, the Company has not come into compliance with its Order in D.T.E. 98-51, and, therefore, the Company should not recover any cash working capital associated with its other operations and maintenance expenses.

3. The Company Has Overstated Its Revenue Lag

The Company contends that its total revenue lag is 58.25 days for purchased power and 68.87 days for purchased gas. Exh. FGE-MHC-1, Sch. MHC-4-1 (electric) and (gas). The revenue lag represents the amount of time between the recorded delivery of service to customers and the receipt of the related revenues from the customers. The Company computes its revenue lag period by adding four time components (measured in days): (1) receipt of service to meter reading; (2) meter reading to billing; (3) billing to collection; and (4) collection to receipt of available funds. Exh. FGE-MHC-1 (Electric), p. 26; Exh. FGE-MHC-1 (Gas), p. 21. For its electric division, the Company claims that the lag for receipt of service to meter reading is 15.21 days; that the lag for meter reading to billing is 2.43 days; that the lag for billing to collection is 38.61 days; and that the lag for collection to receipt of funds is 2 days. Exh. FGE-MHC-1 (Electric), pp. 26-27. For its gas division, the Company claims that the lag for receipt of service to meter reading is 15.21 days; that the lag for meter reading to billing is 2.43 days; that the lag for billing to collection is 49.84 and 20.87 days for Firm and Non-Firm sales respectively; and that the lag for collection to receipt of funds is 2 days. Exh. FGE-MHC-1 (Electric), pp. 26-27. The Company's claimed lag days for meter reading to billing and billing to collection are inflated, unsupported by the record, and/or otherwise inconsistent with industry standard.

a. The Company Has Overstated Its Billing Lag

The Company claims to have a billing lag that adds 2.43 days to its total revenue lag. Exh. FGE-MHC-4, p. 3 (gas). The basis for its billing lag is the number of days between when the Company receives the meter information from its meter readers and when the bill is given to the postal service. *Id.* However, there should not be ***any*** meter to billing lag when using the accounts receivable methodology for determining the revenue lag.

The billing lag starts when the meter reading function ends and ends when the collection lag begins. *Id.* Thus, the billing lag starts when the meter reader downloads the daily read information from the hand held reader to the Company's computer system. According to Company, at the end of the day, the meter read information is then processed into billing information and bills are generated. Exh. AG7-8. With the generation of the customer's bill, the Company should also record an corresponding accounts receivable. Since the collection lag begins with the creation of the accounts receivable, the creation of the bill should, in an efficient accounting system, start the collection lag period Therefore, because the meter read download, the bill generation and the accounts receivable recognition can all occur on the same day, the Department should base the Company's revenue lag calculation on an assumption of a zero day billing lag.

b. The Company's Back Of The Envelope Methodology For Determining Its Collection Lag Overstates That Lag

The Company has used a back of the envelope methodology for determining its revenue lag that in this case clearly overstates the number of revenue lag days its receipts from customers. Exh. FGE-MHC-4, p. 16 (gas). The overstatement of the revenue lag days results in an inflation of the net lag days used to determine cash working capital requirement for all of the Company's gas supply, power supply, and other operations and maintenance expenses.

The Company determined its revenue lag in its last base rate case by actually performing a survey of its bill to measure the actual collection time lag for a sample of bills. Exh. DTE6-34. From that survey, the Company determined a revenue lag of 44.3 days. *Id.* Here, the Company has thrown out the survey methodology, and replaced it with a back of the envelope calculation. Exh. FGE-MHC-4, p. 16 (gas). The calculations determines the revenue lag days by dividing the Company's accounts receivable in any month by the amount of cash received for that same month. *Id.* The theory behind this methodology is that if the Company continues to receive that same daily cash amount, all towards the same month end accounts receivable, it will recover the total receivable balance in that number of days, and that becomes the revenue lag from customer billing to receipt. *Id.*, p.3.

This back of the envelope methodology, while simplistically pleasing, has fundamental flaws that render it useless for determining the Company's cash working capital requirements. One of the most important among the flaws is the assumption that the Company recovers all the total balance of accounts receivable, when in fact it does not. Since the accounts receivable has embedded in it accounts that will never be recovered by the Company, including those receivable that will be written off, the Company's method artificially inflates the days of collection lag. This flaw is critical; in the test year, the Company actually delayed writing off hundreds of thousands of dollars of receivables, until the end of December. Tr. 15, pp. 1914 - 1915. This overstatement of the receivables would result in an artificially inflated collection lag days. The Department should reject the Company's proposed collection lag and instead use the 44.3 collection lag determined from the Company's last case by the more accurate and more reliable survey methodology.

c. The Department Should Remove The Collection To Receipt Of Funds Period That The Company Has Added To The Revenue Lag Days.

The Company proposes to add two days to the revenue lag to reflect claimed period between when the Company records the collection of funds and the time when the Company has receipt of the funds.

The Department has settled the issue of the time required to clear checks. *Commonwealth Electric Company*, D.P.U. 90-331, p. 22 (1991). The Department has found that the check clearing lag is zero, since the payer is obligated to have the funds in the bank account when the check is written. Therefore, the Department should deny the Company's proposed collection to receipt of funds revenue lag and reduce the revenue lag by two days.

4. The Department Should Order The Company To Deduct From Rate Base Customer-Supplied Cost-Free Capital.

Generally, the term "unclaimed funds" refers to customer deposits, payroll checks, voucher checks, and dividend checks. The Company explains that, for the most part, the $1,900 "unclaimed funds" balance in its abandoned property account at the end of the test year "consists of uncashed checks for refunds to customers for security deposits or for final credit balances."[13] - AG-RR-29; Exh. AG-7-10 (Electric); Exh. AG-5-10 (Gas). The Company's explanation confirms that the customers supplied the funds and the funds are available to the Company as cost-free capital. The Company has not segregated those "unclaimed funds" in an escrow account and the Company enjoys full use of these cost-free funds for up to five years before they revert by law to the Commonwealth

Generally, the term "contribution in aid of construction" refers to cash deposits or advances to a utility by a specific customer to fund or aid that customer's specific utility construction needs. Typically, that cash deposit or advance is refunded back to the customer after the completion of the construction. The Company's "contribution in aid of construction" funds are not segregated in an escrow account and the Company enjoys full use of these funds cost-free until they are eventually refunded back to the customers.[14] The Company held a "contribution in aid of construction" funds balance of $176,123 for its electric division and $269,185 for its gas division at the end of the test year. Exh. AG-7-9 (Electric); Exh. AG-5-9 (Gas). The Company's only argument for failing to deduct these balances from rate base is that they are refundable to customers. While it is true that the money will return to customers at some future point in time, the Company has free use of these funds until they are returned.

Department precedent provides that companies must subtract cost-free funds such as "unclaimed funds" and contributions in aid of construction from a utility's rate base. *Western*

[13] The remainder of the balance is a check payable to Lunenberg Water District in the amount of $5.50. Exh RR-AG-29.

[14] The Company's witness, Mr. Collin, testified that the Company pays no interest on the "contributions in aid of construction" funds and that these funds are refundable to the customers. Tr. 8, p. 956.

Massachusetts Electric Company, D.P.U. 85-270, pp. 139-140 (1986); *Boston Edison Company*, D.P.U. 1350, p. 32 (1983); *Eastern Edison Company*, D.P.U. 1580, p. 46, (1984).

The Company failed to deduct the $1,900 of unclaimed funds from rate base. Because such funds are supplied by ratepayers and are a cost-free source of capital for the Company, the should be deducted from the Company's rate base. Accordingly, the Department should order that the Company deduct from its rate base the test year-end balances of $1,900 in unclaimed funds and $176,123 and $269,185 for the Company's electric and gas divisions in contributions in aid of construction.

D. The Department Should Order The Company To Deduct From Rate Base The Company's Capitalized Leases.

The Company proposes to include its test year-end balance of capitalized leases in rate base. Exh. FGE-MHC-1, Schedule MHC-8, line 33 (electric) and Exh. FGE-MHC-1, Schedule MHC-8, line 23 (gas). Capitalized leases are balance sheet items that arise from accounting standards that require firms to record on their financial books the expected liability associated with the annual lease payments for certain long-term leases. Exh. AG-7-72 (electric). The accounting standard FAS 13 requires the Company to record the discount value of those expected lease payments as a liability on its financial books. *Id.* At the same time, the Company records a capitalized lease asset to offset that liability on its balance sheet. The Company proposes the novel addition of its capitalized assets to rate base for the sole reason that capitalized leases are recorded as assets on the Company's balance sheet and therefore, like plant in service, it believes that these balances should be included in rate base. *Id.*

The Department allows a utility to include in its cost of service a return on rate base. Exh. FGE-MHC-1, Sch. MHC-1. This return on rate base is included so that the utility may recover the carrying costs on those investments that it has made in assets that are currently providing utility service to its customers.

The Department should reject the Company's attempt to include its lease payments in rate base. The Company has made no investment in its capitalized leases. This asset is simply an accounting device used to indicate on the balance sheet a contractual obligation associated with the **future** payment for its obligations under those leases. Exh. AG-7-72 (electric). The Company has not made any cash outlay towards those costs and should not get any return on that asset. The Department should therefore, reject the Company's proposal to include capitalized leases in rate base.

E. The Department Should Order The Company To Deduct From Rate Base All Accumulated Deferred Income Taxes.

The Company proposes to reduce its test year end balance of accumulated deferred income taxes by removing balances associated with its gas and electric accrued revenues. Exh. FGE-MHC-1, Schedule MHC-11, p. 1, lines 11 and 12 (electric) and (gas). Company witness Mark Collin testified that these balances were removed, since they were attributable to the energy supply service. Tr. 13, pp. 1580-1581.

The Department's precedent regarding accumulated deferred income taxes is well established. *Commonwealth Electric Company*, D.P.U. 88-135/151, pp. 14-16 (1989); *Western Massachusetts Electric Company*, D.P.U. 182, p. 6 (1975); *Boston Edison Company*, D.P.U. 1350, pp. 5-6 (1983). Utilities are required to include all of their accumulated deferred income taxes as a deduction from rate base.[15] *Id.*

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[15] The Company did assign a balance of accumulated deferred income taxes to the generation function, however, that balance is credited to the unrecovered transition costs through the transition charge.

The Company has removed a balance of accumulated deferred income taxes associated with its accrued revenues, claiming that they are associated with the energy supply recovered in other rates. However, the Company does not credit that balance of accumulated deferred income taxes to the calculation of carrying charges in those energy supply rates. Since this balance of accumulated deferred income taxes is essentially an interest free loan given to the Company, ratepayers should be credited with those costs through the rate base determination in this case. Therefore, the Department should include in the balance of accumulated deferred income taxes the test-year end amount associated with accrued revenues.

IV. OPERATIONS AND MAINTENANCE EXPENSES

A. The Company Improperly Includes Unitil Service Corp. Interest Expenses In Its Cost of Service.

The Company proposes to include USC's interest expenses of $344,945 in the cost of service. Exh FGE-MHC-5 (Electric), p. 3. Interest expenses are properly booked to a 400 account, below the line, and not properly included in the cost of service.

The Department requires the Company to follow its Uniform System of Account is orders to account for its Revenues and Costs, Assets and Liabilities. Specifically the Department Interest expense should be booked to either Account 427 – Interest On Long Term Debt, Account 430 – Interest on debt to associated companies, or Account 431 Other Interest Expense. See the Department's Uniform System of Accounts, and See 18 CFR Ch. 1,part 101.

Fitchburg has many of its back office functions performed by the Service Corp. USC assesses a service charge upon the Company for services rendered to the Company. Tr. 14, p. 1729. These services include carrying costs or interest on borrowed funds. *Id*. at 1729, 1731. USC has incurred $344,945 of working capital carrying costs or short term interest costs that it has charged to the Company. *Id*. at 1728-1731.

The Company proposes to collect this interest assessment dollar-for-dollar as an operation and maintenance expense, charged to Account 923 – Outside Service Employed. This manipulation of the accounting is improper. The Department does not permit companies to include their test year interest expense as a cost item in its revenue requirement determination. Rather, the amount of interest is determined in the return on rate base calculation, as a cost rate weighted by the proportion to total capital, multiplied by the utility's rate base – the investment in assets employed to provide current utility services. The difference in interest expense can be significant.

The borrowings and investments of the Service Corp. are neither reviewed nor are they approved by the Department. The Service Corp. can borrow, invest, and loan for many purposes including the financing of non-utility functions. Furthermore, the Service Corp may incur high cost debt in order to finance these non-utility investments. Finally, the Company could simply be holding onto to borrowed cash in anticipation of paying dividends or making new investments. A review of the day-to-day Service Corp. borrowings, investments, and interest expense incurred should not and practically cannot be part of the Department's review in this case.[16]

The Company has improperly included Unitil Service Corp. interest expense in its operations and maintenance expense, so its accounts do not conform with the Department's and

[16] The Company argues that the Service Corp. interest expense is associated with cash working capital and therefore needs special treatment. Fitchburg, however, recovers cash working capital for all of its operations and maintenance expenses, including those charged from the Service Corp. Therefore, adding in interest expenses again for the Service Corp. would provide the Company with double recovery of those working capital requirements.

FERC's Uniform System of Accounts. Therefore, the Department should remove the Service Corp. interest expense from the Company's pro forma cost of service to insure that the Company does not double recover its interest costs.

B. The Company Overstates Its Bad Debt Expenses.

The Company proposes Bad Debt expenses of $518,429 for its gas division and $272,395[17] for its electric division.[18] The Company's proposed Bad Debt expense figures are inflated and overstate the Company's actual Bad Debt or uncollectible expenses. The Department should reject the Company's proposed Bad Debt expenses and should instead adjust or revise these expense figures to reflect actual uncollectible expenses.

The Department determines a utility's pro forma bad debt expense by averaging the most recent three years' net writeoffs and applying the average to determine the percentage of adjusted test-year revenues it represents, i.e. the uncollectible ratio. *See Boston Gas Company*, D.P.U. 96-50 (Phase I) , at 70-71 (1996); *Berkshire Gas Company*, D.P.U. 90-121, at 96-97 (1990); *Western Massachusetts Electric Company*, D.P.U. 84-25, at 113-114 (1984). Although the Company claims that it followed the Department's standards for calculating Bad Debts,[19] in fact it deviated from the substance of those standards with its recording of write-offs at the end

[17] The Company's total bad debt for the electric division is $615,218, which the Company reduced by $342,843 to account for anticipated recovery in standard offer and default services, leaving a remaining balance of $272,395.

[18] The Company calculates its $518,429 bad debt figure for the gas division as 2.46% of its 2001 normalized revenues and calculates its $272,395 bad debt figure for the electric division as .70% of its 2001 normalized revenues less the amounts recoverable through standard offer or default service. *See* Exh. FGE-MHC-1, Schedule MHC-7-10 (Gas); Exh. FGE-MHC-1, Schedule MHC-7-8 (Electric).

[19] The Company explains that it totaled the past three years (1999, 2000 & 2001) of net write-offs and firm revenues and adjusted or otherwise calculated these figures to derive Bad Debt expense for ratemaking purposes. Exh. FGE-MHC-1 (Gas), p. 44-45; Exh. FGE-MHC-1 (Electric), pp. 47-48.

of the test year.

Company witness Mark Collin testified that early in the test year independent auditors expressed concern about the Company's level of over-90-day arrears.[20] Tr. 13, p. 1558. Despite this warning from auditors, the Company failed to adequately address this problem or potential problem in a timely fashion.[21] Mr. Collin also testified that the Company wrote off additional amounts in December before closing out its fiscal year. *Id*. at 1559.

The inclusion of the write-offs in the final month of the year artificially inflates Bad Debt because this recording irregularity does not to take into account recoveries that might take place the following month(s) in the subsequent year. The Company recorded more than one-third of its test year gross electric write-offs, and over 40% of its test year gross gas write-offs, in December. Tr. 15, pp. 1914, 1916. Mr. Collin acknowledged that for the months January through November, the average electric gross write-off per month was $39,521 and the average gas gross write-off per month was $36,727. *Id.* at 1916. For the month of December, however, the Company recorded an electric gross write off of $225,109 and a gas gross write–off of $302,228. The Company's stockpiling of write-offs and recording them in December avoids reconciliation and thus artificially inflates its Bad Debt expense. This late attempt to catch up on its writeoffs provided the Company no time to perform any recoveries on those amounts. Indeed, the Company's witness admitted that all of the recoveries associated with the huge December writeoff would be made sometime during the year 2002.

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[20] Mr. Collin testified that the auditors audited the Company's records every quarter. Tr. 13, p. 1558.

[21] If the auditors warned the Company early in 2001about the over-90-day arrears, and continued to review the Company on a quarterly basis, these auditors probably continued to warn the Company about these arrears during each subsequent review. The Company did not address its arrears problem until the end of the year.

The Department should not allow this arbitrary accounting manipulation to skew the Company's net write-offs The Department should require the Company to exclude the extraordinary December write-offs from its Bad Debt expense calculations and direct the Company to use the average gross write-offs per month for the months January through November in the test year for its Bad Debt expense calculation.

C. The Company Improperly Includes Advertising Costs For New Hampshire Advertisements In Its Cost Of Service.

The Company proposes to include advertising costs of $1,994 for its electric division and $1,006 for its gas division in its cost of service. Exh. FGE-MHC-1; Exh. AG-7-24 (Electric); Tr.8, p. 961. A portion of these costs, $1,994, is for advertising and marketing costs in New Hampshire relating to a New Hampshire property. *See* Exh. AG-7-24, Attachment 1. These costs are unrelated to Massachusetts and/or Massachusetts consumers and should not be included in the Company's cost of service. As the Company admitted, "if this is a New Hampshire-related charge, it should be removed from the Fitchburg cost of service." Tr. 8, p. 962. The Department should remove the New Hampshire advertising and marketing costs of $1,994 from the Company's cost of service.

D. The Company's Methodology In Amortizing Software And Technology Assets Is Inconsistent And Irregular And Related Expenses May Be Improperly Allocated.

The Company proposes to increase its test year software and technology amortization expenses dramatically, to $129,666 for its gas division and $252,442 for its electric division. Exh. FGE-MHC-1, Schedule MHC-7-21 (Gas); Exh. FGE-MHC-1, Schedule MHC-7-18

(Electric).[22]

The Company provided a list of amortization periods for various software and technology assets, which shows that the Company inconsistently uses varying amortization periods for similar software and technology assets. Exh. RR-DTE-4; Exh. AG-7-65(Electric); *see also* Tr. 9, p. 1044. The Company should be consistent in the amortization periods it uses for similar assets.

The Company incurred various software and technology costs for items it purchased or upgraded. The Company, however, failed to amortize those costs for the respective year of the purchase or upgrade. Tr. 7, pp. 890-892. For example, the Company upgraded an accounting system in the year 2000 but did not amortize any of those costs that year.[23] The same held true for the Company's web page; the Company incurred costs in 2001 but did not amortize any of those web page costs that year. *Id.* at 925. Indeed, the Company seemed confused or otherwise unable to accurately explain its methodology in amortizing its web page amortization. *Id.* at 920-925. The Company also provided contradictory information by stating that amortization on its customer information system began in 1998, even though the Company listed 1997 as the date amortization began on this entirely new system. *Compare* RR-DTE-4; Exh. AG-7-5 (Electric); Tr. 8, pp. 910-912. The Company should be required to begin amortizing its software and technology assets from the in-service date of that asset.

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[22] The Company proposes to increase its software and technology amortization expense by almost three times, from $44,279 in the test year to $129,666 for its gas division, an increase of $85,387. Exh. FGE-MHC-1, Schedule MHC-7-21 (Gas). For its electric division, the Company proposed to increase its software and technology amortization expense over four times, from $62,370 in the test year to $252,442, an increase of$190,072. Exh. FGE-MHC-1, Schedule MHC-7-18 (Electric).

[23] Company witness Mark Collin testified that, in the year 2000, the Company conducted an accounting system upgrade costing $51,628, which amount the company carried over to the following year without any amortization during the year 2000. Tr. 7, p. 890. The same held true for the MVRS site license, for which the Company incurred a cost of $12,714. *Id.* at 891-892.

Finally, Collin testified that USC employees and other affiliate company employees use the customer information system, but suggested that USC has no need for customer service and therefore does not pay for any use of the customer information system. Tr. 14, pp. 1770-1772. The costs of the customer information system, together with the other software and technology assets, have substantially increased the amortization expense which the Company's customers ultimately must pay. The Department should require the Company to accurately allocate the costs of the software and technology assets among all affiliates that use or otherwise benefit from these assets.

The Department should deny the proposed increase to test year software and technology amortizations because the Company has not proved that its amortization periods and allocations were proper.

E. The Department Should Disallow the Company's Rate-Case Legal Expenses Entirely And Require Normalization Rather Than Amortization of Other Rate Case Expenses.

Fitchburg is under a specific and affirmative duty to contain all of its rate case expenses. *Fitchburg Gas And Electric Light Company*, D.T.E. 98-51, p. 57 (1998). Several years ago, the Department put Massachusetts utilities on notice that outside legal and consulting services must be subject to a competitive bidding process, or an adequate justification must be provided for the failure to issue a request for proposal ("RFP"). *Boston Gas Company*, D.P.U. 96-50, p. 79 (1996). Invoices for services provided to the utility should contain sufficient detail to describe the nature of work. *Fitchburg Gas And Electric Light Company*, D.T.E. 98-51, p. 61. Vague or general descriptions are simply insufficient. *Id.* Failure of a Company to adhere to any of these requirements may result in disallowance of the requested rate case expense. *Id.* pp. 56-61.

Fitchburg did not issue an RFP to solicit competitive bids for legal services in connection with the rate case and did not provide a credible explanation for this failure during the hearings. Tr.11, pp. 1321 - 1322. The Company took no formal steps to determine whether another law firm would charge either a lower hourly rate or could prepare and defend the rate petitions in fewer billable hours. Tr. 11, pp. 1323 - 1324. Although the Company claimed that it received a written hourly rate discount, Tr. 11. P. 1326, this statement was contradicted by the record. AG-RR-44.[24] Since the Company has not met the Department's standard, the Department should reject the Company's requested recovery of the portion of rate case expense for legal services.

The Company deferred and amortized the remainder of its rate case expense. Tr. 7, pp. 879-880, 883. Exh. FGE-MHC-1, Schedule MHC-7-18 (Electric); Exh. AG-7-5, Attachment (Electric); Tr. 7, pp. 879-883. Department precedent provides that rate-case expense should be normalized rather than amortized. *Fitchburg Gas and Electric Light Company*, D.T.E. 99-118, at 39-40. The Department has explained that:

> [a]s a general rule, rate case expenses are normalized rather than amortized, but parties often use these terms interchangeably. There is a reason for the use of the particular items. Amortization implies a utility is guaranteed a dollar-for-dollar recovery of the costs, while normalization is intended to only show a representative level of expenses in rates.

Berkshire Gas Company, D.T.E. 01-56, p. (2001). The Company claims that its method fits the definition of "normalization." Tr. 7, p. 886. The Company admits, however, that it is confused, stating "[s]o even in this case, the terms "normalization" and "amortization" get kind of mixed and matched through the proceeding, so you can see how this concept can be difficult to follow. *Id.* at 888.

The Department should require the Company to adhere to Department precedent and

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normalize its rate-case expense. Since the Company has a ten year price cap plan pending, the normalization period should be ten years. *Berkshire Gas Company*, D.T.E. 01-56, p. 74 (2002) (appropriate to normalize rate case expense over ten year period of the plan).

F. The Company's Proposed Pro Forma Adjustment To Property And Liability Insurance Is Excessive and Not Supported By The Record.

The Company proposes to include in its cost of service for its electric division a pro forma property and liability insurance expense in the amount of $227,808. Exh. FGE-MHC-1, Schedule MHC-7-7 (Electric).[25] Even though this proposed insurance expense is almost double the amount of the test year insurance expense, the Company fails to adequately explain why it should be granted this amount and fails to support its request with record evidence. The Department should reject the Company's proposed pro forma insurance expense and should disallow recovery of any amount greater than the test year amount.

Company witness Mark Collin testified that the Company did not increase the coverage on any existing policy. Tr. 13, p. 1560. He attributed the extraordinary increase or doubling of the Company's insurance premium to simply a change or "hardening" of the market, an explanation apparently received from the Company's broker. *Id.* at 1562. The Company did not indicate that it sought to negotiate lower premiums with its insurer or that it solicited any bids for insurance or "RFPs" from insurance carriers. Indeed, nothing in the record evidence suggests that the Company made any effort to control the cost and substantial increase in this expense. The Department should not reward the Company's negligence in failing to act on this

[25] The electric test year property and liability insurance expense totaled $116,670. In contrast to the nearly doubling of the electric expense, the Company proposes a property and liability insurance expense of $120,637 for its gas division, $9,116 less than the test year insurance expense amount of $129,753. Exh. FGE-MHC-1, Schedule MHC-7-9.

issue with a blanket approval of a 100% increase to that expense. The Department, therefore, should reject the Company's proposed pro forma insurance expense and should disallow recovery of any amount greater than the test year amount.

G. The Department Should Disallow Recovery of Non-Union Wage Increases Because The Company Has Not Shown That The Amounts Are Reasonable

The Company proposes to increase its operations and maintenance expense to provide for increases in its non-union wages for the years 2002 (4.9%) and 2003 (4.8%). Revised Sch. MHC-7-3 (electric) ($103,418) and revised Sch. MHC-7-5 (gas) ($107,379). The Department should disallow all of the proposed non-union wage increase, $210,797 in total, because the Company's overall compensation package (wage and benefits) for its employees already is well above the median level for utilities and all industrials.

The Company supports its request with a 1998 Hay Group analysis based on 1997 surveys of industrial and utility firms. The Company claims that those surveys indicate that the Company's employees' salaries were insufficient. DTE 4-5 (common). Based on those results, the Company then gave its non-union employees annual salary increases greatly exceeding the industry averages in order to bring them in line with those of the compared companies. The Company is also relying on the Hay Group's assertion that it benchmarked those increases using data from 2000-2002 wage and benefit surveys. Exh. FGE MHC-1, p. 41 (electric) and Exh. FGE MHC-1 (gas), p. 38; Tr.1, p.101; Tr. 11, pp.1349-50. The Company did not list the names of the 2000-2002 wage and benefits surveys upon which the Hay Group relied for benchmarking purposes, did not describe the relevant chapters or charts that formed the basis of the Hay Group's evaluation, and did not make available for cross examination a representative from the Hay Group. AG-RR-7.

The Department has allowed increases for non-union salaries and wages when the increases are reasonable and in line with similar utility employees of other companies. *See Berkshire Gas Company,* D.T.E. 01-56, p. 54 (2002); *Blackstone Gas Company*, D.T.E. 01-50, p. 9 (2001); *Boston Gas Company*, D.P.U. 96-50 (Phase I), p. 42 (1996) citing *Fitchburg Gas & Electric Light Company*, D.P.U. 1270/1414, p. 14 (1983). To meet this standard, a company must demonstrate: (1) an express commitment by management to grant the increase, (2) an historical correlation between union and nonunion raises, and (3) that the amount of the non-union increase is reasonable. *Id*; *Massachusetts Electric Company*, D.P.U. 95-40, p. 21 (1995).

Here, the Company fails to meet the third part of this standard. To determine the reasonableness of non-union base wages and increase, the Department compares how a company's proposed non-union based payroll and increases with the wages paid to employees at similarly-situated companies that compete for skilled employees. *Berkshire Gas Company*, D.T.E. 01-56, p. 55 (2001); *Massachusetts Electric Company*, D.P.U. 92-78, pp. 25-26 (1992); *Bay State Gas Company*, D.P.U. 92-111, pp. 102-103 (1992). To allow the Department to determine the reasonableness of a company's total employee compensation expense, companies must provide comparative analysis of their employee compensation expenses. *Boston Gas Company*, D.P.U. 96-50 (Phase I), p. 47 (1996). The Department should examine current total compensation expense levels and proposed increases in relation to other New England investor-owned utilities and to companies in a utility's service territory that compete for similarly skilled employees. *Id; Massachusetts Electric Company*, D.P.U. 95-40, p. 27 (1995).

The Company's current wage and benefit levels and requested increases are not reasonable and the Company's total compensation for its non-union employees is well above that of both all industrial firms and utilities. The Department should look to the overall compensation package (wage and benefits), not just the wage component, in determining the reasonableness of the Company's request. *Massachusetts Electric Company*, D.P.U. 95-40, p. 26 (1995). A careful review of the 1997 Hay surveys and the 1998 Hay Study upon which the Company relies show that the Company's total wage and benefit package greatly exceeded the industrial and utility averages for that year. AG RR 7; Tr. 12, pp. 1527-1531.[26] Furthermore, the 1997 Hay surveys and 1998 Hay Study use compensation packages from organizations that generate over $1 billion dollars in annual revenues (and their abilities to attract qualified employees through its wage and benefits packages) as the standard for the Company, yet the Company generates just $90 million in annual revenues and Unitil generates about $207 million annually. AG 1-2(4) Attachment 1, p. 19. This is an order of magnitude in difference that renders the comparison unreasonable.

Comparisons between the 1997-1998 Hay data and subsequent wage and benefit surveys are meaningless, unreasonable, and unreliable because the 2001 Hay Reports and the 2000-2002 surveys use different job classification systems, use different (or no) Hay Point scale system, and use different methodologies.[27] One survey which appears to be somewhat applicable to the Company regionally is a 2001 Compdata survey of New England utilities and other industrials sponsored by the Greater Boston Chamber of Commerce. The Company, however, gives no indication that this volume was used in preparation of its rate case. AG RR 7. Because the

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[26] Indeed, if the Department allows Company further increases in its salary structure, it would only be fair and equitable that it require a decrease in the Company's benefits recovery to bring them in line with those of the compared group, thus requiring a corresponding decrease in those benefit costs to bring them in line with industry averages.

[27] See Hay Compensation Report, 2001 Compensation Planning Guide – General Industry Management; August 24, 2001 Cover letter, "market charts using new methodology."

Company did not refer to the surveys by name and section, the Department would have to speculate as to whether the Company actually used this or any other 2000-2002 survey volume as the basis its payroll adjustment justification.[28]

The Company's benchmarking analysis for employee salaries is unreliable and misleading, given its benefits package which greatly exceeds that of industrials and utilities alike. The Company's analysis in this case does not show that its non-union employees are under-compensated when one considers the employees' combined salaries and benefits. To the contrary, it appears that they are probably overcompensated relative to comparable companies. Therefore, the Department should deny the Company's requests for all increases in its non-union salaries, which is $210,797.

H. The Department Should Order Additional Allocations of Expenses To Non-Utility Operations.

According to the Company, it has made adjustments to its pro forma cost of service to remove the revenues and costs associated with its non-utility water heater program, an unregulated affiliate. The Company has failed, however, to allocate any of the following five pro forma expense increases to the Company's unregulated affiliate: (1) property and liability insurance expenses ($111,138, Sch. MHC-7-7 [electric] and (-)$9,116, Sch. MHC-7-9 [gas]); (2) medical and dental expenses ($22,729, Sch. MHC-7-4 [electric] and $37,844, Sch. MHC-7-6 [gas]); (3) PBOP and retiree trust fund expenses ($54,556, revised Sch. MHC-7-6 [electric] and

[28] The Company provided the Attorney General and Department with copies of the Compdata 2001 survey and the remaining 9 volumes of 2000-2002 surveys on the last day of hearings, September 10, 2002. This gave the Attorney General, parties and the Department no meaningful opportunity to review these voluminous documents (over 3800 pages), prepare and cross-examine the Company's witness on his use of the 2000-2002 surveys. Without any citations or comparison to the numbers in those surveys, the Department should afford this data absolutely no weight in its analysis and findings in this case.

$11,513, revised Sch. MHC-7-8 [gas]); (4) property tax expenses ($128,062, Sch. MHC-7-16 [electric] and $166,327, Sch. MHC-7-19 [gas]); and (5) amortization of intangible assets; ($190,072, Sch. MHC-7-18 and $85,387, Sch. MHC-7-21). The Company must make reasonable allocations of costs to its affiliates that share assets and costs with the utility. *See Berkshire Gas Company*, D.P.U. 92-210, p. 5 (1993). These additional allocations are necessary to ensure that ratepayers do not subsidize the business costs of these affiliates. *Blackstone Gas Company*, D.T.E. 01-50, p. 12 (2001).

These five pro forma adjustments represent common costs in which the unregulated affiliate must share to avoid improper ratepayer subsidies. The Company and its water heater rental affiliate are insured under the same property and liability insurance policies and the same self-insurance plan administered by Anthem Blue Cross/Blue Shield for medical and dental expenses. AG-1-63. The Company and its affiliate share the same retirement trust fund and use portions of the same real estate that is subject to property taxes. The Company and the affiliate share the same intangible assets that have been amortized.

Since the Company has not allocated any of these pro forma expenses to the Company's affiliate, the Department must assign a value for each allocation. *Blackstone Gas Company*, D.T.E. 01-50, p. 12 (2001). The Company has allocated these expenses based on a ratio of the non-utility revenues to utility revenues 1.0802% (revised Sch. MHC-7-5 gas and revised Sch. MCH-7-3 electric). The Department should use the same percentage to assign these cost adjustments to the non-utility function, and reduce these five pro forma expenses by 1.0802% based on the revenue ratio.

I. The Department Should Deny Both Of The Company's Proposed Adjustments To Post-employment Benefits Other than Pensions (PBOPs)

The Company proposes to make two pro forma adjustments to its cost of service for its Post-retirement Benefits Other than Pensions ("PBOPs"): (1) FAS 106 expense related to current employees, and (2) Retiree Trust Fund expense for retired employees. The Department should disallow both of the PBOP adjustments.

All PBOP adjustments included in the cost of service must reflect an actual cash disbursement to the FAS 106 trust fund consistent with the Company's tax-deductible amount under FAS 106. *Massachusetts Electric Company*, D.P.U. 95-40, p. 39 (1995), *citing Massachusetts Electric Company*, D.P.U. 92-78, p. 83 (1992).[29] This treatment takes into account the uncertainties surrounding FAS 106 factors such as inflation medical cost predictions, medical trend assumptions, and future technological changes. *Boston Gas Company*, D.P.U. 93-60, p. 213 (1994).

The only known and measurable trust fund amount that the Department can rely on in this case is the test year amount of contributions to the Retiree Trust Fund. Exh. FGE-MHC-1, Sch. MHC-7-6(Electric), Sch. MHC-7-8 (Gas). The Department, therefore, should reject the Company's proposed adjustment to the cost of service for an estimated contribution to the Retiree Trust Fund because it does not meet the Department's known and measurable standard. Furthermore, the Department should reject the Company's proposed FAS 106 expense adjustment since it made absolutely no corresponding contribution to a PBOP trust fund to cover that cost. *Massachusetts Electric Company*, D.P.U. 92-78, p. 83. For these reasons, the

[29] "The Department finds that funding the tax-deductible amount is consistent with Department precedent and strikes the best balance in allocating PBOP expenses appropriately between current and future ratepayers and between ratepayers and shareholder." *Massachusetts Electric Company*, D.P.U. 95-40, pp. 39-40 (1995).

Department should deny both of the Company's proposed PBOPs adjustments.

J. The Department Should Disallow The Company's Proposed Recovery of Insurance Premium Increases Because The Company Has Not Taken Sufficient Steps To Contain Costs

The Company has asked the Department to include in the Cost of Service increases in various insurance premiums that the Company experienced during the test year. Exh. FGE-MHC-1, Sch. MHC-1-7 (electric); Exh. FGE-MHC-1, Sch. MHC-7-9. The Company failed to contain its insurance costs, failed to attempt to reduce its premiums, and now seeks an unreasonable insurance expense that should be disallowed. The Company did not try to reduce the premium increases for its Directors and Officers liability insurance (118%), excess liability insurance (22%), all risk insurance (56%). Tr.11, pp. 1384-92. The Company should have sought quotes from another insurance broker or should have issued a Request for Proposal ("RFP") for another broker. *Berkshire Gas Company*, D.T.E. 01-56, p. 60 (2002); *Boston Gas Company*, D.P.U. 96-50, p. 46 (1996).

As with the Company's rate case legal fees, the Company has, under the guise of maintaining comfortable business relationships, has failed to protect its ratepayers from excessive charges. The existence of "continuity credits" does nothing to ameliorate the Company's lack of due diligence because the Company paid thousands of dollars in off-setting consulting fees to the broker for no apparent benefit. Exh. AG-7-35, Attachment, p. 11; Tr.11, p.1377-80 The Company must demonstrate that its expenses are reasonable, and failing to question significant premium increases is not a reasonable approach. Since the Company not met its burden, the Department should deny the prosed increase.

K. The Department Should Disallow Proposed Medical and Dental Expense Increases Because they Are Unreasonable And Not Known And Measurable.

The Company proposes to increase its test year cost of service by $22,769 (Sch. MHC-7-4 electric) and $37,844 (Sch. MCH 7-6 gas), to reflect a 26 percent increase in its projected costs for its medical claims. Test year health care expenses must be: (1) known and measurable, and (2) reasonable in amount. *Berkshire Gas Company*, D.T.E. 01-56, p. 60 (2001); *Boston Gas Company,* D.P.U. 96-50 (Phase I), pp. 45-46 (1996); *North Attleboro Gas Company*, D.P.U. 86-86, p. 8 (1986). In addition, utilities must contain their health care costs. *Berkshire Gas Company*, D.T.E. 01-56, p. 60 (2001); *Boston Gas Company*, D.P.U. 96-50, p. 46 (1996); *Massachusetts Electric Company*, D.P.U. 92-78 , p. 29 (1992); *Nantucket Electric Company*, D.P.U. 91-106/138, p. 53 (1991).

Anthem Blue Cross/Blue Shield ("BC/BS")administers the Company's self-insurance plan, charging a fee for those services. As administrator, BC/BS bills a monthly amount to the Company to cover the costs of the program. The Company then receives credits to the payments to compensate for any differences between the estimated claims and the actual claims. The Company pays BC/BS a fee to act as the administrator, and the fee is based on the premium set aside by the Company for claims paid.[30] Tr. 8, p. 971-2.

The requested 26 percent estimated increase in claims paid is nothing more than an estimate and certainly not known and measurable. The record (even in the Company's late-filed response to DTE-RR-63) fails to contain any true-ups to actual claims paid. The Department should reject the Company's unsubstantiated medical expense increase.

[30] Since BC/BS's fee is based on its estimated premium there is incentive for BC/BS to overestimate the premium to increase its fee.

The Company's proposed increase is also clearly unreasonable. The increase is more than the forecasts of other experts in the field of medical claims. The Company's estimate of overall medical cost increase is more than twice the expected increase given by the Company's own actuaries, which are projecting an only eleven percent increase in medical costs for 2002. AG-RR-62. For all the reasons set forth above, the Department should reject the Company's proposed medical claims expense increase and limit it to a maximum of an eleven percent increase.

L. The Department Should Reject The Proposed Incentive Compensation Plan Expenses Because It Does Not Benefit Customers.

Fitchburg employee expense in the Unitil Service Corp. charges to the Company during the test year include an employee incentive program cost. FGE MHC-1, p. 36, 40 (electric); FGE MHC-1, p. 33, 37 (gas). The Department should disallow a portion of the employee incentive program costs from the cost of service because the adjustment is based on shifting incentive goals are not measurable and known.

The Department reviews a company's proposed compensation adjustments to determine whether the adjustments are known and reasonable. *Massachusetts Electric Company*, D.P.U. 95-40, p. 12 (1995). Also, adjustments to the cost of service for an incentive compensation program must be: 1) reasonable in amount; and 2) reasonably designed to encourage good employee performance. *Boston Gas Company* D.P.U.93-60, pp. 98-99 (1994). Incentive plans must have defined goals and quantifiable benchmarks that benefit ratepayers. *Id.*; *Bay State Gas Company*, D.P.U. 92-111, p. 115 (1992).

The Company made incentive payments to all Fitchburg employees as well as to those of the Unitil Service Corporation. The test year incentive payments were based on several goals:

earnings - 30%; reliability - 10%; low costs - 10%; customer satisfaction - 10%; new business initiatives - 20%; and subjective evaluation - 20%. DTE 4-9; AG 1-36; Tr. 15, pp. 1903.

At a minimum, the Department should disallow the part of the payroll adjustment resulting from (1) the earnings goal, (2) the new business incentives and, (3) the subjective evaluation goal. Such payment goals are undefined, and the sums paid for reaching them are unreasonable, unquantifiable and not known or measurable by an objective standard. First, the Company started with a 30% goal weight for earnings, but later during the test year shifted to a 40% goal weight, without explanation. DTE 4-9, Attachments 2 and 3. This rendered the earnings goal a shifting, undefined, unpredictable, and therefore unmeasurable goal. Also, the Company assigned a 20% goal weight to the "subjective evaluations" goal to recognize employees who capitalized on unplanned opportunities and responded to unforeseen problems. DTE 4-9, Attachment 3. Finally, the new business initiatives provided no direct nor indirect benefit to customers of the utility are clearly subjective. These three goals are inherently subjective, not objective, and consequently also unmeasurable. The Department should, therefore, disallow the proportionate part of the payroll adjustment that resulted from the subjective goals within the incentive payment plan.

M. The Company's Is Improperly Expensing Its Costs Of Meter Removals

The Company, incurred a cost of $56,164 associated with electric meter removals and $21,715 associated with gas meter removals during the test year in this case. The Company is currently expensing the cost of its meter removals. Exh. FGE-JHA-1, p. 113 (gas). The Company cites to the Department's Uniform System of Accounts as the basis for this accounting treatment. Exh. AG-4-21.

The cost of removal is included a cost of plant. See Exh. AG-4-21, p. 30, Item 254 and

Exh. FGE-JHA-1, pp. 5 and 9 (electric and gas). These costs should be capitalized and recovered through a utility's depreciation expense. *Id*. The Department's Uniform System of Accounts allows the Company to expense "the cost of removing ***and*** resetting meters." (emphasis added). Exh. AG-4-21 (gas).

The Company improperly expensed all of its meter removals during the test year in this case, particularly those where the Company removed and retired the meters. Since the Department directs companies that remove and retire plant to always charge those costs to the plant account, the cost to remove and retire meters should also be capitalized. Exh. AG-4-21, p. 30, Item 254. It should be noted that the Department's instruction does not note any exclusions or exceptions as to many of the other instructions. Furthermore, this instruction fits perfectly with the concept of expensing of those costs only in the cases of "removal and resetting." Clearly, it is the Department's intent to have companies expense those costs of resetting the meters as though they were maintenance expenses. This interpretation is both logically and in conformance with basic accounting principles. Therefore, the Department should disallow the Company's test year expenses for meter removals and order the Company to capitalize those costs in the future.

N. Revenue Requirement Adjustments Made During and after the Hearings in this Case

The Company has proposed a multitude of new adjustments to its cost of service, during and after the hearings. In fact, on the day that this brief is being filed, the Company is still proposing new adjustments to its proposed cost of service as the result of late filed responses to record requests. Exh. DTE-RR-6 (electric) and (gas) and Exh. DTE-RR-43 (electric). The Attorney General reserves his right to object to such late-filed adjustments,and where appropriate will address any legitimate adjustments in his reply brief in this case.

V. DEPRECIATION

A. Introduction

The Department allows utilities to include in their cost of service depreciation expense. Depreciation expense is included to provide the utilities with recovery of the cost of plant in service over its useful life. Depreciation expense for any period is determined by multiplying the balance of plant in service by the depreciation accrual rate. The depreciation accrual rate, using the remaining life method, is determined by summing the undepreciated balance of plant in service and the cost of removal, subtracting the salvage value, dividing that amount by the average remaining life of the plant, and expressing that amount as a percent of the total plant balance.

The Company sponsored the testimony of a James H. Aikman. Exh. FGE-JHA-1. Mr. Aikman performed depreciation studies for both the electric and the gas divisions of Fitchburg. *Id*. Sch. JHA-1. The Company, as a result of Mr. Aikman's study, proposes to increase its depreciation expense by $1,065,000, or 55 percent for its electric division and $210,000 or 13 percent for its gas division.

The magnitude of these increases by themselves are unjust and unreasonable, especially given the fact that just three years previous to the depreciation study done for this case, the Department approved the study that produced the current rates. The Company did not attempt to explain these huge increases in depreciation expense that would cause each customer to incur and additional $39 per year for electric service. Rather, Fitchburg simply assumes, with no discussion or explanation, that the "judgment" of its current depreciation witness can overrule and replace the "judgment" of the previous witness, in D.T.E. 98-51. This type of "opinion shopping" should be rejected by the Department and the Company's proposed change in depreciation accrual rates should be rejected in whole by the Department.

Notwithstanding the arguments above that the Department should reject the Company's entire proposal to change depreciation accrual rates because of the "opinion shopping," there are other flaws in the depreciation study that should cause the Department to reject the Company's requested increase in depreciation accrual rates. Each of these arguments will be discussed separately below.

B. Mr. Aikman Failed To Perform A Study Of Gas Mains By Material Type

The Department should deny the Company's proposed depreciation accrual increase for its gas division because Mr. Aikman has failed to follow the directives of the Department to perform a gas main actuarial study bu material type. The Department Order in *Berkshire Gas Company*, D.T.E. 01-56, p. 95 regarding Mr. Aikman's depreciation analyses was clear. He was ordered to perform his mains actuarial analyses by material type. Id., p. Neither Mr. Aikman nor the Company should by rewarded for his failure to perform this required study.

Mr. Aikman's failure to perform the gas main plant by material type has an obvious and significant impact on the assumed of the plant in those accounts. Gas service mains have historically been made of different materials. *See* Exh. AG-4-9 (gas). These materials include wood, wrought iron, cast iron, steel, coated steel and plastic. Each material type has its own unique characteristics which cause the Company to install, maintain, and retire them in different ways.

Here Mr. Aikman performs his actuarial analyses for gas mains by combining all of the mains with the various material types together as though their characteristics were all the same.

Clearly, as the Department has found they are not all the same. *Berkshire Gas Company*, D.T.E. 01-56. The Department has ordered the gas distribution companies with the Commonwealth to replace certain cast iron mains due to their high failure rates. The Company has agreed to replace approximately 2 miles feet per year under the program approved by the Department. D.T.E. 00-PL-05. This artificial early retirement of those cast iron mains is obviously driving down the average service life of all mains including those of steel and those of plastic.

The dollar balance of cast iron mains that the Company is retiring through this program is small relative to the steel and plastic mains. Although the Company has 408,862 feet of cast iron main in the ground the dollar balance associated with the cast iron plant is only $2,717,750. Exh. AG-4-9 (gas). Thus, the actuarial lives of all of the other different main types are being improperly driven down by the early retirement of the cast iron mains that make up only 16 percent of the total balance of gas mains. *Id.* Any analysis that does not recognize, and account for these fundamental characteristics of the different main materials is on its face useless for the Department's determination of their actuarial lives. Therefore the Department should reject Mr. Aikman's depreciation study and recommendation in this case and order the Company to provide a gas distribution main study by material type to be performed in its next base rate case.

C. Mr. Aikman Failed To Apply His Small Increment Approach To Changes In The Elements Of The Depreciation Accrual Rate Calculation

Mr. Aikman's methodology that he employs in his depreciation study in this case is internally inconsistent and unreasonable and should be rejected by the Department. Mr. Aikman explains at great lengths why his engineering "judgment" is critical above all history, facts and statistical analysis in determining the depreciation accrual rates. Yet, here his "judgment" causes him to change his methodologies mid stream in order to increase the depreciation accrual rate.

Mr. Aikman has had a long standing rule that he would not immediately change from the existing estimated useful life for any plant account to the actuarial life that results from his statistical analysis, even if the statistics have recurred in study after study. Tr. 2, pp. 206-207. His preferred method, and the one often approved by this Department, is to make small, incremental movements towards the actuarial results that represent ten to twenty percent of the difference. *Id*. Thus, for example, if the Company' existing life estimate for mains were 70 years and the results of actuarial analyses had consistently indicated a life of 90 years, Mr. Aikman would increase his recommended life by ten percent of the difference or a two-year increment to move slowly towards the indicated amount.

The fatal flaw in Mr. Aikman's analysis is his failure to make similar "conservative" small increment changes when he performs his net salvage value analysis, especially with regard to the electric plant accounts. Here, Mr. Aikman has no fear in moving 50 or 100 percent of the way from the existing estimated net salvage value to the one that results from the most recent study. Mr. Aikman's misapplication of his incremental approach causes very significant increases in plant cost recovery. In fact, Mr. Aikman's failure to consistently apply his incremental approach causes some plant account recommendations to increase by as much as 100 percent.

There are many electric plant accounts where Mr. Aikman failed to apply his incremental approach to changes in the net salvage estimates. The failure to apply this approach results in astonishing increases in plant account cost recoveries. Below are listed certain of the accounts where Mr. Aikman has misapplied his incremental approach, the resulting increase, and the change consistent with his incremental approach are present in the following table:

NET SALVAGE ANALYSIS

	Previous Study	New Study	Aikman Proposal	Aikman Increment	Corrected Increment At 10% Of Difference	Net Salvage With Corrected Increment
Account 352	(10)	(68.3)	(50)	(40)	(5.8)	(15.8)
Account 353	5	(49.5)	(40)	(45)	(5.5)	(0.5)
Account 355	(5)	(150)	(100)	(95)	(14.5)	(19.5)
Account 356	0	(128)	(80)	(80)	(12.8)	(12.8)
Account 362	10	(71.1)	(40)	(50)	(8.2)	1.8
Account 364	(10)	(129)	(100)	(90)	(11.9)	(21.9)
Account 365	(5)	(123.7)	(85)	(80)	(11.8)	(16.9)
Account 366	(5)	(120.4)	(80)	(75)	(11.5)	(16.5)
Account 367	(5)	(116.5)	(50)	(45)	(11.2)	(16.2)
Account 368	5	(8.8)	(10)	(15)	(1.4)	3.6
Account 369	(15)	(135.2)	(125)	(110)	(12)	(27)
Account 371	20	(87.8)	(75)	(95)	(10.8)	9.2
Account 373	(10)	(71.8)	(75)	(65)	(6.2)	(16.2)

Exh. AG-4-1 (electric), Exh. DTE -1-19, Ech. FGE-JHA-1, Sch. JHA-1, p. 38-39. This table simply corrects Mr. Aikman's net salvage value analysis to make it conform to his incremental change analysis that he uses for the other components of the depreciation accrual rate. Reasoned consistency requires that Mr. Aikman consistently apply his incremental change methodology to all of the components of his depreciation study, not those that just bias his results towards a higher accrual rate. Therefore, the Department should reject Mr. Aikman's net salvage estimates for the accounts indicated above and instead use those that are developed in that table.

VI. REVENUES

A. The Department Should Adjust For Increased Post-Test Year Revenues Of Newark America, The Customer That Replaced Princeton Paper.

In the electric division's last rate review, the Company persuaded the Department to adjust for the post-test year reduction in revenues no longer received from a large customer, Princeton Paper Company, LLC ("Princeton"). *Fitchburg Gas & Electric Light Company*, DTE 99-118, pp. 14-20 (2001). Princeton had filed for bankruptcy and sold its facilities to another paper company, Newark America Company ("Newark"). Id. The Department reduced the Princeton revenue loss adjustment by Newark revenues because it found that the "loss of Princeton and gain of Newark are sufficiently related that we cannot accept the one and exclude the other," and reduced the Company's revenues by $1,218,092. *Id.*, pp. 19-20.

The Department generally sets rates to reflect the likely cost and revenues assuming the same level of service provided in the test year. *Boston Gas Company*, D.P.U. 88-67 (Phase I) at 140 (1988). If the addition or deletion of a customer or change in customer sales, either during or after the test year, represents a known and measurable change to test year revenues, and constitutes a significant adjustment outside of the "ebb and flow" of customers, then the Department may include a representative level of revenues for purposes of deriving a utility's revenue requirement. *Fitchburg Gas & Electric Light Company*, DTE 99-118, pp.16-20 (2001); *Massachusetts-American Water Company*, D.P.U. 88-172, at 7-9 (1989); *Western Massachusetts Electric Company*, D.P.U. 558, at 70-72 (1981).

Newark continued to pay the Company relatively small revenues during the 2001 test year. After the test year, however, Newark's actual electric loads and revenues rose markedly. Tr. 1, pp. 48-57; Exh. AG 7-53 & supplement (confidential); AG-RR-3 (confidential); AG-RR-58, p.3 (confidential). The post-test year increase in Newark's load and revenues is known and measurable. The record contains Newark's actual electric loads and electric delivery service revenues by month for 2002. AG-RR-3 (confidential); AG-RR-58 (confidential). Mr. Collin testified that Newark's recent post-test year sales and demand numbers are both known and definite. Tr. 1, p.55. *See* Exh. AG 7-53 & supplement (confidential) and RR-3 (confidential).

The increase in Newark's load and revenues after the test year is clearly significant and outside the ebb and flow of customer changes. Newark's actual electric loads for the four most recent months were, on average, almost 15 times the test year average. Exh. AG 7-53 & supplement (confidential); AG-RR-3 (confidential).[31] Newark's revenues, similarly, have risen dramatically since the test year. AG-RR-58 (confidential). Any doubt about the significance of the post-test year increase is eliminated by comparing current annualized electric delivery service revenues (based on the most recent four months) from Newark to Princeton's $1.3 million revenue for 1999 that the Department found justified an adjustment. AG-RR-58, p.3; *Fitchburg Gas & Electric Light Company*, DTE 99-118, p.20 (2001).

Under Department precedent and for purposes of fairness and symmetry with the Princeton post-test year adjustment, the Department should order Fitchburg to include a post-test year revenue adjustment by subtracting Newark test year electric delivery service revenues from

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[31] Mr. Collin testified that Newark is approaching a load of 10 megawatts. Tr. 1, pp. 49. This load represents about 11 percent of the approximately 90 megawatt total demand on Fitchburg's system, which is clearly significant. *Fitchburg Gas & Electric Light Company*, DTE 99-118, p.18 (2001);

an annualization of the actual Newark electric delivery service revenues from May-August, 2002. *Id.*

VII. COST OF DEBT

A. The Company Overstates its Cost of Debt.

The overall weighted cost of capital proposed by the Company results in a windfall to the Company to the detriment of its customers. The method by which the Company proposes to calculate its cost of capital results in customers paying a significantly higher rate than what the Company actually pays for its capital costs. The Department should require the Company to include all debts, both long-term and short-term, in its calculation of its overall weighted cost of capital.

The Company's cost of service includes a return on rate base which provides the Company's investors a return on the net investment that they have made in its utility business. Exh. FGE-MHC-1. The return compensates the debt holders and the common stockholders for their investments in the Company's utility business.[32] The manner in which the Company calculates it cost of capital results in the Company greatly overstating that cost.

A substantial portion of the Company's cash needs are funded through short term debt which bears a lower interest rate. The Company testified that it borrows from the Unitil money pool and incurs this short-term debt to fund various short term and long term projects and operations. Tr. 1, 65-68. The Company further testified that it is a net borrower from the Money Pool. *Id.* at 66. During the test year, the Company had $69 million in total outstanding debt of

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[32] The dollar amount of the return is determined by multiplying the dollar amount of the rate base by the overall cost rate of these different costs of capital weighted by the amount outstanding of each type of capital. Exh. FGE-MHC-1, Sch. MHC-12(electric).

which $15,225,847 or 22% consisted of short term debt. A substantial portion of the Company's operations, then, are funded through short term debt. Exh. FGE-1, Sch.MHC-12(Electric); Exh. AG 1-6, Att.3. The Company, however, excluded that short term debt and its accompanying lower interest rate is excluded from consideration in the Company's calculation of its overall weighted cost of capital.

The Company and its shareholders receive a windfall from being able to charge customers for the carrying costs on investments, including cash working capital, at its overall pretax cost of capital of 12%, while paying short-term interest rates in the 4% range. The Department can prevent this stockholder windfall by including short-term debt in the Company's capital structure used to determine its overall cost of capital.

VIII. COST OF EQUITY

A. Introduction

The cost of service includes a return on rate base which provides Fitchburg's investors a return on the net investment that they have made in its utility business. Exh. FGE-MHC-1, Schedule 1. The return compensates the debt holders, the preferred stockholders, and the common stockholders for their investments in the Company's electric and gas distribution businesses. Exhibit FGE-MHC-1, Schedule 12 (electric and gas). The dollar amount of the return is determined by multiplying the dollar amount of the rate base by the overall cost rate of these different costs of capital weighted by the amount outstanding of each. *Id*.

The Company sponsored the testimony of Mr. Samuel C. Hadaway regarding its cost of common equity. Exh. FGE-SCH-1 (electric and gas). As will be discussed below, there many flaws with his analyses that cause his results to greatly overstate the Company's cost of common equity. Most important, however, is his fundamental misunderstanding of the purpose of these proceedings and the risk and expected returns on an electric and distribution service company.

B. Mr. Hadaways's Risk Analysis Totally Misstates The Investment Risks Associated With The Provision Of Distribution Service

The cost of the Company's common equity is not readily measurable in the manner that its costs of debt and preferred stock are. Exh. FGE-SCH-1, p. 4 (electric and gas). Since Fitchburg Gas & Electric Light Company's common stock is held by its parent corporation Unitil Corporation, it is impossible to determine the market cost of equity for the Company's stock using any market approach.[33] Therefore, Mr. Hadaway performed his analysis on a group of companies that he deemed comparable to the Company (the "comparison group"). Tr. 10, pp. 1145-1146.

Mr. Hadaway discusses on at great length the various risks of different investments in the electric and gas industries in a way that would bias his recommendation upward. Exh. FG&E-SCH-1, pp. 19-23 (electric and gas). He describes the risks of the Western United States market that has been in an energy crisis, the risk of deregulation, open access to the transmission grid, and increased competition in the electric and gas industry." *Id.* The fact is, however, that investment in Fitchburg's electric and gas distribution service has nothing to do with **<u>any</u>** of these risks. While these risks may be applicable to vertically integrated utilities in California, they are totally inappropriate for the Company's electric and gas distribution businesses. Furthermore, Mr. Hadaway's group of comparison companies contain firms that operate subsidiaries whose investment risk is much greater than that of Fitchburg. The electric

[33] Since Fitchburg Gas & Electric Light Company is comprised of both as well as an electric division, it has a blended cost of common equity for both divisions, further complicating a direct analysis of the cost of equity of the business at issue in this case.

companies in the comparison group have affiliates whose operations include unregulated generation that include affiliates that carry substantially higher risk than a regulated distribution company. These companies include the following businesses, as indicated by the check marks:

ELECTRIC COMPARISON GROUP BUSINESSES

	Vertically Integrated	Energy Trading	Unregulated Generation	Other Gas Utility	Unregulated Businesses
Alliant Energy	✔	✔	✔	✔	✔
Ameren	✔		✔	✔	
Cinergy	✔		✔	✔	
CLECO	✔	✔	✔		✔
Consolidated Edison			✔	✔	
Constellation	✔		✔	✔	✔
DPL	✔		✔	✔	✔
DQE					✔
Energy East				✔	✔
Entergy	✔	✔	✔	✔	
FPL Group	✔		✔		✔
NSTAR				✔	✔
Potomac Electric	✔				✔
P. S. Enterprise	✔		✔	✔	✔
SCANA	✔			✔	✔
Southern	✔		✔		✔
TECO	✔		✔		✔
UIL Holdings					✔

See Exh. AG-6-15 and AG-6-16 (electric).

The gas companies in the comparison group have affiliates whose operations include unregulated operations that include affiliates that carry substantially higher risk than a regulated distribution company. These companies include the following businesses:

GAS COMPARISON GROUP BUSINESSES

	Energy Marketing	Oil & Gas Exploration	Other Unregulated Businesses
AGL Resources	✔		✔
Atmos Energy	✔		✔
Cascade Natural Gas			
Energen		✔	
Laclede	✔		✔
Nicor		✔	✔
Northwest N.G.			✔
Peoples Energy	✔		
Piedmont	✔		✔
Southwest Gas			
WGL Holdings	✔		✔

See Exh. AG-8-15 and AG-8-16 (gas).

Therefore, Mr. Hadaway's DCF analysis, which uses comparison groups consisting of firms with vertically integrated electric companies including the "risky" generation, energy trading and oil and other unregulated businesses and gas distribution companies that have pipeline, energy trading, and oil and gas exploration businesses, overstate the cost of equity for Fitchburg's electric and gas distribution business. Indeed, Mr. Hadaway could not even identify the business for which the Department was setting rates in these cases. Tr. 10, pp. 1140-1145. When asked if the Department should determine the rates in D.T.E 02-24 based on the cost of equity capital for a gas distribution company, he responded, "no." Id, pp. 1144-1145. When asked if the Department should determine the rates in D.T.E 02-25 based on the cost of equity capital for an electric distribution company, he again responded, "no." *Id.*, p. 1145. Apparently, Mr. Hadaway believes that it is appropriate for his comparison group to includes companies whose businesses are different from and whose investment risks are significantly different from that of Fitchburg's gas and electric distribution businesses without making any adjustments to his analysis to recognize those different investment risks. For this reason alone, the Department should reject Mr. Hadaway's inflated recommendations in this case.

The Department has recognized the lower risk of the stand-alone distribution business. *Massachusetts Electric Company*, D.P.U. 95-40, pp. 95-96 (1995). In D.P.U. 95-40, the Department found that a distribution company has less risk (and thus a lower required return) than utilities that have generation and non-utility subsidiaries. *Id*. The Department should also find that Mr. Hadaway's DCF cost of equity analyses overstate the cost of common equity for Fitchburg because they depend on a broad group of vertically integrated companies that have generation, energy trading, oil and gas generation, as well as non-utility subsidiaries.

C. Discounted Cash Flow Analysis

Mr. Hadaway performed a discounted cash flow ("DCF") analysis of the two comparison groups, one for his electric division analysis and one for his gas division analysis. Exh. FGE-SCH-1, Sch. SCH-4 (electric and gas). As was discussed *supra*, the investment risk of his comparison group of integrated electric and gas companies is greater than that of the Company's distribution businesses alone. Therefore, Mr. Hadaway's DCF cost of equity results are all biased upward. Notwithstanding this fact, there are still other critical flaws in Mr. Hadaway's DCF analyses that will be discussed below.

The theory underlying the DCF analysis is that the market price that an investor is willing to pay for a share of common stock is equal to the present value of the cash dividends and the proceeds from the sale of the investment when the investor divests those shares. Exh. FGE-SCH-1, pp.11-12. Mr. Hadaway used three different DCF approaches to estimate the cost of equity for the comparison group. Exh. FGE-SCH-1, Sch. 4. Each will be discussed below.

1. Constant Growth

One approach to the DCF analysis is to assume that the growth in dividends per share is constant over time (the "constant growth rate model"). *Id.*, pp. 11-12. The DCF theory can be modeled then by the following equation:

$$k = \frac{D_1}{P_0} + g$$

where k = the investors' required return on common equity;
D_1 = the dividend per share paid in the next period;
P_0 = the current market price per share of the common stock; and
g = the investors' mean expected long-run growth rate in dividends paid per share.

Id., pp. 11-13.

Some of the components of the model are easily measured such as the current price per share and the current dividend paid. *Id.*. However, the investors' expectations of the growth in dividends over the next year and over the rest of the investors' holding period are not directly measurable. *Id.* Since it is impractical to measure all of the investors' expectations regarding their growth rate estimates, it is necessary to use a proxy for those expectations. These proxies include historical and forecasted measures of the dividends, earnings, and book value per share growth rates as well as the growth from retained earnings. Exh. AG-6-15 (electric) and Exh. AG-8-15 (gas).

Mr. Hadaway applied this analysis by taking the average of three different proxies for the growth rate. Exh. FGE-SCH-1, Sch. 4, page 2 (electric and gas). Mr. Hadaway did not even use historical measures of growth, but relied solely on forecasted measures as represented by Zack's five-year earnings per share growth rate, the *Value Line Investment Survey's* three to five-year earnings per share growth rate, and a measure of growth from retained earnings calculated from *Value Line*. *Id*. These growth rates resulted in an average growth rate estimate of 7.17 percent for the gas comparison group and 5.94 percent for the electric comparison group. *Id*.

Theses short-run forecasts of growth rates that Mr. Hadaway uses are too high to be representative of a long-run sustainable growth in electric utility stocks. The growth rate in Gross Domestic Product has been around 5.57 percent recently (see D.T.E. 99-118, p. 74), the average ten-year historical growth rate in earnings per share, dividends per share, and book value per share which have all been substantially lower. See Exh. AG-6-15 (electric) and AG-8-15 (gas).

COMPARISON GROUPS HISTORICAL GROWTH RATES

Ten-Year Historical Growth Rate	Electric Comparison Group	Gas Comparison Group
Dividends Per Share	1.8 %	2.0 %
Earnings Per Share	2.4 %	2.6 %

Id.

In comparison, Mr. Hadaway's average growth rate estimate of 7.17 percent for the gas division and 5.94 percent for the electric division is well above what has been experienced in the past and can be expected in the future.

The Department should reject Mr. Hadaway's estimates of the long-run growth rates and the DCF cost of equity estimates that he derives from those forecasts. First, they more than double the growth rates that these companies have experienced in the past. Mr. Hadaway never explained how regulated gas and electric distribution companies could expect in the long-run to increase their earnings at rates more than twice that which they have achieved during the last ten years. Second, Mr. Hadaway's growth rate estimates exceed the expected growth in the economy. Finally, Mr. Hadaway derives all of his estimates from forecasts made by firms that sell stock or mutual funds, firms which have a decided interest in inflating their growth rate estimates in order to do more business. See Exh. AG-6-18 (electric) and AG-8-18 (gas). While it is impossible to measure the actual amount of the overstatement of the forecasts for any one institution, it is clear from the extent of the recent investigations of the Securities and Exchange

Commission, the United States Congress and the New York Attorney General's Office that the inflation of forecasts is systematic and wide spread. For all of these reasons, the Department should reject Mr. Hadaway's inflated DCF growth rate estimates he uses for his Constant Growth Rate DCF.

A reasonable approach to estimating the growth rate for Mr. Hadaway's constant growth rate DCF is to provide consideration for both the long-run historical growth rate in dividends and earnings per share and the expected growth in the economy. For the comparison group of electric companies, this creates a range of growth rates from 1.8 to 5.25 percent. When summed with the average dividend yield for the comparison group of electric companies of 5.14 percent this range yields a DCF cost of equity estimates from 6.94 to 10.39 percent with a midpoint of 8.67 percent. For the comparison group of gas companies, this creates a range of growth rates from 2.0 to 5.25 percent. When summed with the average dividend yield for the comparison group of electric companies of 4.78 percent, this range yields a DCF cost of equity estimates from 6.78 to 10.03 percent with a midpoint of 8.41 percent.

2. Terminal Value DCF

The second approach that Mr. Hadaway used is his Terminal Value Approach. This DCF approach assumes that the investor holds the investment for a certain number of years and then sells the investment at a certain price. Exh. FGE-SCH-1, Sch. 4, p. 3. In this case, Mr. Hadaway assumed that investors held the stock for three to four years and then sold the stock at the end of the last year. *Id*.

Mr. Hadaway relied heavily on *Value Line Investment Survey* for his estimates of investors' expectations for each of the companies in his comparison group. *Id*. Specifically, he derived from *Value Line's* data an estimate of the dividends per share paid for each of the intermittent years as well as a price per share of the stock in the last year. *Id*. Here again, Mr. Hadaway has essentially derived a cost of equity estimate from short-term forecasts. All of the forecasts that he uses to derive his Terminal Value DCF are five-year values or less. Exh. AG-6-15 (electric) and AG-8-15 (gas). The Department should not rely on such short-term expectations of one analyst to estimate the long run expectations of the whole market. Furthermore, as is discussed above, these estimates based on forecasts from institutions that sell stocks and stock funds are now widely believed to be overinflated. Therefore, the Department should reject Mr. Hadaway's Terminal Value DCF approach and the resulting cost of equity estimate.

3. Two-Stage Growth Rate DCF Model

The third DCF approach that Mr. Hadaway uses is the Two-Stage Growth Rate approach. Exh. FGE-SCH-1, Sch 4, p. 4 (electric and gas). This model is based on the assumption that there is some short-term growth rate in dividends per share that investors expect, followed by a different growth rates that are expected for periods thereafter. *Id*. Here, Mr. Hadaway uses the following model.

$$P_0 = D_0(1+g_1)/(1+k) + \ldots + D_0(1+g_2)^n/(1+k)^n + \ldots + D_0(1+gT)^{(T+1)}/(k-g_T)$$

Mr. Hadaway started by using the Value Line forecasted dividends per share growth rate for the first five years of the this approach. Exh. FGE-SCH-1, Schedule SCH-4 (gas and electric), p. 4. After the first five years, Mr. Hadaway assumes that growth will jump to the long-run growth rates which remains constant after that. *Id*. Mr. Hadaway's long-run growth rate estimates of 7.17 percent for gas distribution companies and 5.94 percent for electric distribution companies was based his the short-run growth rate projections. *Id*.

Mr. Hadaway provided no support for using short-run growth rate estimates to estimate the long-run growth, for years 6 through 150, for his comparison group. Not only is this methodology theoretically flawed, the resulting growth rates are clearly in excess of the expected growth rate of economy and do not make any sense as estimates for the long-run growth rate for a regulated electric and gas distribution companies.

A utility Company cannot expect continuously to grow faster than the economy as a whole. With inflation at less than 2.25 percent (see Exh. AG-6-5 (electric), Gross Domestic Product Chain Weighted Price Index) and real growth in the economy expected at less than three percent (see Exh. AG-6-23(electric), page 1 (growth not to exceed 3%) and page 3 (growth 2-3%), 5.25 percent is a reasonable estimate of the long-run average nominal growth rate in the economy. This amount is consistent with the growth rate experienced during the eleven years of robust growth through 2001, which has been 5.57 percent. See D.T.E.99-118, pp. 74. Furthermore, as indicated above, the ten-year historical growth in dividends per share and earnings per share for electric and gas companies is so low, being less than 2.5 percent, both electric and gas companies. Since electric and gas distribution utilities cannot sustain, in the long-run, a level of grow higher than that of the economy, then the utility's long-run growth rates should conservatively be capped at 5.25%. If the Department corrects Mr. Hadaway's Non-Constant Growth Rate DCF analysis for his comparison group of electric companies, using the more reasonable estimate of 5.25 percent as the long-run growth rate for the period after 5 years, the result is a decrease in the cost of equity estimate of almost two hundred basis points or two percent for his gas distribution company analysis to less 9.5 percent and almost 50 basis points or one-half of a percent for his electric distribution company analysis to less than 10 percent. This Non-Constant Growth Rate DCF analysis for his comparison group provides a more theoretically correct and a more logical basis for determining the cost of equity for an electric company. Therefore, the Department should reject Mr. Hadaway's Two-Stage DCF analysis and, instead employ the more reasonable long-term growth rates that are no higher than the overall growth in the economy.

4. Discounted Cash Flow Analysis Summary and Recommendation

The Department should reject the DCF analyses as proposed by Mr. Hadaway. His applications of the DCF approaches are based on inconsistent and illogical choices of model elements that in each case bias his results upward, causing his cost of equity results to be grossly inflated. Instead, the Department should base its decision on those analyses that are applied consistently, without the picking and choosing of elements that inflate the results. Using the appropriate elements to each DCF approach the appropriate cost of equity estimates are as follows:

	Electric	Gas
Constant Growth DCF	8.67 %	8.41 %
Two-State Growth Rate DCF	9.5 %	10.00%

Thus, a range of rates from 8.67 percent to 9.5 percent provides a reasonable basis (with appropriate adjustments discussed *infra)* for the Department's decision on the Company's electric division cost of equity. Furthermore, a range of rates from 8.41 percent to 10.0 percent provides a reasonable basis (with appropriate adjustments discussed *infra)* for the Department's decision on the Company's gas division cost of equity.

5. Risk Premium

Mr. Hadaway performed several risk premium analyses as a check on the results. Exh. FGE-SCH-1, pp. 28- 31 (electric) and pp. 26-28 (gas). The risk premium approach is based on the assumption that investors require a higher return on their investment for them to hold assets of greater risk. Exh. FGE-SCH-1, pp. 6-7 (electric and gas). In each of his applications of the risk premium, Mr. Hadaway has mis-specified the risk premium, causing his results to be either meaningless or inappropriate for determining the cost of equity for Fitchburg.

6. The "Authorized ROE" Risk Premium

Mr. Hadaway provides a risk premium analysis based on the "authorized ROE" of various gas companies. Exh. FGE-SCH-1, pp. 24-25 (electric); Exh. FGE-SCH-1, pp. 22-24 (gas) and Exh. FGE-SCH-1, Schedule 5 (electric and gas). He determined the risk premium by taking the 22-year average of the difference between the returns on common equity ordered by utility commissions in each year and the average public utility bond yield for that same year. *Id*. Both of these elements to the risk premium have flaws that cause the risk premium to be meaningless.

The bond yield that Mr. Hadaway uses is Moody's Average Public Utility Bond Yield. See Exh. AG-6-10 citing Exh. AG-6-1 (electric) and Exh. AG-8-10 citing Exh. AG-8-1 (gas). This average yield includes electric and gas companies that are mostly vertically integrated, as well as telephone companies. *Id*. It is not in any way specific to the electric distribution business, nor is it specific to the gas distribution business. Therefore, the Department should reject Mr. Hadaway's risk premium analysis since the debt component used to determine his risk premium represents all utilities and not the specific distribution utilities that are under investigation in this case. See *Boston Edison Company*, D.P.U. 1350, p. 169 (1983).

The "authorized ROE" that Mr. Hadaway uses to determine his risk premium is an inappropriate measure of investors, cost of equity expectations. The underlying principle behind the risk premium analysis is that one is attempting to measure investors' expectation of the premium. Exh. FGE-4, pp. 17-18. Mr. Hadaway's "authorized ROE" approach has as its basis commissioners' cost estimates, not investors estimates, therefore, **it is not a market based analysis**. Furthermore, since commission decisions are based on record evidence that can be six months older and more, the commission ordered returns will necessarily be lagging behind the then current market information. Therefore, any comparison between the ordered returns and the bond yields is meaningless.[34]

7. Ibbotson Risk Premium and Harris-Marston Risk Premium Analyses

Mr. Hadaway performs two other risk premium analyses into his prefiled testimony to bias his cost of equity analyses upwards. Exh. FGE-4, pp. 26-27. He included an analysis based on Ibbotson Associates data ("Ibbotson Risk Premium") and an analysis based on Harris-Marston study data ("Harris-Marston Risk Premium"). *Id.* Without going into the many problems that the Department has already found with the use of the Ibbotson and Harris type data, suffice it to say that such historical data has been resoundingly rejected by the Department for use in determining the cost of equity for a utility company.[35] *Boston Gas Company*, D.P.U. 96-50, p. 128 (1996); *Massachusetts Electric Company*, D.P.U. 95-40, p. 97 (1995); *Boston Gas*

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[34] A year to year comparison of the bond yields and the "authorized ROEs" shows how the returns lag the bond yields over time. See Exh. FG&E-4, Schedule 5,p.1

[35] Interestingly, although Mr. Hadaway includes the Ibbotson risk premium numbers in his cost of equity analysis in this case, he went on to state specifically, that he does not endorse Ibbotson's methodology. Tr. 10, pp. 1120-1129. Furthermore, he goes on to say that he uses neither the Ibbotson nor the Harris-Marston risk premium analyses in this case to determine the cost of equity for the Company. *Id.*

Company, D.P.U. 93-60, p. 262 (1993); *Bay State Gas Company*, D.P.U. 92-111, p. 256-266 (1992). More important however, is the fact in both cases, the measure for the cost of equity was not an electric distribution company of similar investment risk to Fitchburg, nor for that matter a utility company. Rather, Mr. Hadaway used in both cases the cost of equity of the Standard & Poor's 500 to determine the risk premium. Tr. 2, p. 211 (referring to the Ibbotson study) and Exh. AG-6-14, p. 3. Since the Standard & Poor's 500 is generally considered to have investment risk greater than that of utility distribution companies, using this risk premium will necessarily bias the results upwards. Therefore, the Department should reject Mr. Hadaway's Ibbotson and Harris-Marston Risk Premium analyses, since they bear no relation to the Company's cost of equity.

If notwithstanding the Attorney General's arguments regarding the Company's risk premium analyses, the Department decides that the Ibbotson risk premium analysis should be given weight in this proceeding, then it should require that analysis toconform with that recommended by the studies' authors. D.T.E. 99-118, p. 87. Ibbotson recommends using the equity risk premium in the capital asset pricing model formula. *Id*. The formula sets the market required cost of equity equal to the riskless rate as measured by the yields on U.S. Treasury plus the equity risk premium times beta. *Id* . Based on the evidence in the record, the equity risk premium over long-term government bonds is 7.0 percent, over intermediate government bonds is 7.2 percent, and over U.S. Treasuries is 8.8 percent. Exh. AG-6-13 (electric). The most recent six month average of the yields on long-term, intermediate-term, and 30-day U.S. Treasuries are 5.8 percent, 4.36 percent, and 1.725 percent, respectively. See Exh. AG-6-5 (electric), Tr. 10, pp. 1172-1173, and Tr. 10, p. 1173. The beta for the comparison group of electric companies is 0.54 and the beta for the gas companies is 0.61. See Exh. AG-6-15 (electric) and AG-8-15 (gas).

Therefore, depending on an investor's holding period (or investment horizon), the associated market returns for the comparison group of electric companies would be as follows:

ELECTRIC COMPANY RISK PREMIUM ANALYSIS

	Long-Term Investment Horizon	Intermediate Investment Horizon	30-Day Investment Horizon
Riskless Rate	5.8%	4.36%	1.73%
Market Premium	7.0	7.2	8.8
Beta	0.54	0.54	0.54
Equity Risk Premium	3.78	3.89	4.75
Cost Of Equity	9.58%	8.25%	6.48%

Therefore, if the Department were to use the Ibbotson Associates study, the appropriate cost of equity analysis derived from that study would determine a cost of equity for the comparison group of electric companies in the range of 6.48 percent to 9.58 percent with a mid-point of 8.03 percent.

Similarly, depending on an investor's holding period (or investment horizon), the associated market returns for the comparison group of gas companies would be as follows:

GAS COMPANY RISK PREMIUM ANALYSIS

	Long-Term Investment Horizon	Intermediate Investment Horizon	30-Day Investment Horizon
Riskless Rate	5.8%	4.36%	1.73%
Market Premium	7.0	7.2	8.8
Beta	0.61	0.61	0.61
Equity Risk Premium	4.27	4.39	5.37
Cost Of Equity	10.07%	8.75%	7.09%

Therefore, if the Department were to use the Ibbotson Associates study, the appropriate cost of equity analysis derived from that study would determine a cost of equity for the comparison group of gas companies in the range of 7.09 percent to 10.07 percent with a mid-point of 8.58 percent.

8. Risk Premium Analysis Summary and Recommendation

Mr. Hadaway's risk premium analyses are fundamentally flawed in their measures. They are either mis-specified or are totally meaningless for determining the cost of equity for the Company. The Department should reject all of Mr. Hadaway's risk premium analyses.

D. Cost of Equity Summary and Recommendation

The Department should reject Mr. Hadaway's DCF and risk premium analyses. His risk premium analyses are fundamentally flawed and shed no light on the Company's cost of equity. On the other hand, his DCF analysis is biased upward by his selective rejection of analysts' forecasts and the models behind the approaches. Only by applying the approaches in a consistent and unbiased manner can one establish a basis for a reasonable estimates of the cost of equity for the companies in his comparison group. These applications yield a range of reasonable returns for the electric companies of 8.67 to 9.5 percent. The applications for the gas companies yield a range from 8.41 to 10.0 percent. Since these results reflect those of companies with higher risk, given that they are vertically integrated companies with generation and marketing risk requirements, and given the unsatisfactory performance of Company management, as discussed *supra*, the Department should choose a cost rate at the lower end of that range. For all of these reasons, the Department should reject the Company's requested allowed return on common equity and in its place use a 8.67 percent return for the electric division and 8.41 percent for the gas division.

IX. COST ALLOCATION AND RATE DESIGN

A. The Department Should Reject the Proposed Design Day Allocation of Gas Costs Because It Would Be Contrary To Cost Causation, Would Not Replicate Either The Market Or Capacity Assignment And May Make The CGAC Unreviewable.

The Company proposes to collect its gas revenue requirement through rates based on fully allocated cost of service studies prepared by Mr. James Harrison, who also testified for the Company in its last gas rate case, DTE 98-51. In this case, Mr. Harrison developed the various allocators used in the cost studies to distribute to specific functions and rate classes both the distribution base rate revenue requirement and gas costs in the Company's load factor-based cost of gas adjustment clause ("CGAC"). As in the Company's last rate case, Mr. Harrison uses his ever-evolving "market-base allocation" ("MBA") methodology to allocate gas related costs.[36]

[36] The MBA method allocates the cheapest gas supplies to the High Load Factor classes (G-51, G-52, G-53 and R1/R2 classes) and the most expensive gas supplies to the Low Load Factor classes (G-41, G-42, G-43 and R3/R4 classes). Exh. FGE-JLH-1(Gas), pp. 8-12. For reasons expressed in previous cases, the Attorney

In this filing, the Company proposes for the first time to implement the MBA by applying a design day-based allocator to gas costs in the CGAC.[37] Use of Mr. Harrison's design day-based allocator for remaining capacity costs, either capacity or commodity, would represent a move away from allocating on the basis of cost causation. The Company's current CGAC is based on an MBA methodology that does not utilize a design day allocator for remaining capacity cost, but rather allocates all costs above base costs on proportional responsibility, which better reflects when gas is actually used by the various classes. The Company does not select its portfolio of gas supply resources based solely on its design day. Fitchburg's acquisition policy is not driven by the need to meet a design day peak, as Harrison's methodology implies. Although the Company must acquire an adequate gas supply to meet its design day peak, its decisions about acquiring gas are designed to minimize the cost of a reliable supply during normal weather.

For example, the Company may need to have a supply that could provide 1,000 MMBTU for a design day. Fitchburg will determine the actual mix of gas sources that make up that 1,000 MMBTU, however, by considering its total gas costs during a normal winter–with the goal of minimizing total winter gas costs. If the Company truly considered only the design day, it would use more gas with lower demand costs than it would choose based on a normal winter. The lower demand cost gas usually produces more expensive commodity costs. Thus, a typical portfolio would show that as the Company reduces its underground storage capacity and

General does not think that the MBA method is appropriate for cost allocation generally, but is not contesting that method here because the Department has approved it in several previous cases.

[37] The Department adopted a design day-based allocator approach proposed by Mr. Harrison in the Berkshire Gas Company's most recent rate case, DTE 01-56 (2001).

increases its peaking gas, it would reduce capacity costs (associated with storage), but at the same time it would increase total costs, as it would have less underground storage commodity available and would have to buy more expensive commodity cost gas. Some of the gas that normally has the most expensive commodity costs, *i.e.*, liquid natural gas ("LNG"), is needed on an ongoing basis for balancing. Mr. Collin described how daily load variations on many days would be met with LNG. Tr.12, p.1477. Further, underground storage "is not as flexible as LNG." Tr.12, 1481. The Company would need some LNG to provide flexibility even if it could meet its design day with underground storage. In fact, Mr. Collin agreed that "LNG was pretty useful during the whole winter period." Tr.12, p.1484). "Remaining gas" capacity costs therefore should be allocated based on some measure of contribution to normal winter use, not design day.

Using the design day method for allocating supplemental gas costs does not mimic the market. There is no evidence that the so-called Market Based methodology reflects competitive market pricing. No marketer has purchased the model, and Mr. Harrison was not able to test the model by comparing its results to competitive prices, since these prices are not public. Tr.4, pp. 422-424. The Company's capacity allocation method simply allocates to a departing customer a total slice of capacity based on an estimate of the customer's design day peak load. The slice is itself made up of separate slices of different types of capacity determined by the Company's existing portfolio. None of these slices resemble a marketer's portfolio. First, a marketer would acquire the amount of capacity that the customer contracted for, which is unlikely to equal the theoretical computation of the customer's design day. Second, a marketer would put together a portfolio that would minimize the cost of serving the customer. There is no reason to expect that portfolio to look anything like the portfolio that the Company put together over many years to serve its total load and to meet its regulatory responsibility--the estimated design day load.

The proposed gas allocation methodology contains a fundamental inconsistency. The proposed CGAC would allocate capacity on design day and then allocate commodity costs (except for "base" costs) on a different method, one that is based on normal winter use. A high load factor customer would pay a lower share of demand costs based on the design day allocator than on a normal winter use or even a normal peak allocator, yet the allocation of commodity costs to that customer would be based on normal weather usage. If the proposed CGAC change is accepted, this high load factor customer inconsistently would be assigned the costs of more underground storage gas than he was charged capacity costs for. This would be unfair to other customers because the commodity cost of underground storage gas is usually fairly reasonable and less than LNG.

Mr. Harrison apparently incorporated the design day in an attempt to replicate the way that the LDCs are allocating capacity to migrating customers under the mandatory capacity allocation program adopted by the Department as part of the introduction of retail access. *See: Investigation by the Department of Telecommunications and Energy upon its own motion commencing a Notice of Inquiry pursuant to 220 C.M.R. § 2.00 et seq. into the unbundling of all natural gas local distribution companies' services*, DTE 98-32-B (1999). The major rationale for allocating "remaining demand" costs on the basis of an estimate of design day peak is to mimic the Capacity Assignment to migrating customers. This does not mean that allocating remaining demand costs on this basis reflects cost causation and is theoretically correct. It also does not mean that the CGAC is now designed so that migration will not impact other customers. Presumably, allocation of demand costs is intended to mean that the customer will have to pay for the same amount of capacity whether they purchase from the Company or purchase from an alternative supplier. This will not be the case under the Company's proposed design day allocator. The design day peak calculation for Capacity Release is different from the design day calculation for the class. According to AG-RR-45, the computation for a migrating customer is based on an estimate of that customer's design day peak that relies on daily load data for that customer, whereas the CGAC class allocation is based on monthly data. Moreover, the particular migrating customers may have utilized gas commodity in a different manner from the class average. In other words, the released capacity may be used by these customers to transport, buy, and store different amounts of gas than they had been paying for through the CGAC. Simply allocating "remaining capacity costs" with a class design day estimate does not result in a CGAC that will prevent migration or necessarily treat other customers fairly with regard to all costs.

There are other problems with the design day allocator in addition to its failure to reflect cost causation. First, the Company has not made clear what its CGAC methodology would be. Until after August 15, more than three months after the Company filed Mr. Harrison's and Ms. Asbury's testimony, the record in this case did not even reveal that the Company was planning to use a different method and process to develop the Company's CGAC allocators than that testified to by Mr. Harrison, a fact not revealed in Ms. Asbury's pre-filed testimony. AG-RRs-18 and 45-47.

The computation of the design day allocator in each CGAC would be so complicated that it would be difficult to review and may be unreviewable. In fact, the methodology proposed is so complicated that there is no evidence that the Company will duplicate it entirely in its

CGAC filings.[38] AG-RR-45.This complexity would make future CGAC filings less transparent and reviewable.

Using the design day allocator in the CGAC also would involve the exercise of too much judgment in estimating the design day. Ms. Asbury testified the CGA tariff "…is intended to be a **general guideline** for how the calculations are performed." Tr.6, p. 721 (emphasis added). There likewise are "not any specific formulas for how capacity is assigned" to migrating customers. Tr.6, p. 723.

Lastly, the computation of the design day allocator in the CGAC would actually be based on different data, including for weather normalization,[39] than are used and examined in this case.

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[38] In addition to the problems associated with the design day allocator, the base gas definition in the current MBA is incorrect. Base costs are supposed to represent the amount of gas that the Company must contract for to meet load in its lowest use months. This is then allocated on the basis of customers' base use. The definition of base gas costs is not adequate to cover summer use. Commercial and industrial use is lower on weekends than on weekdays, yet daily base use is defined as the summer usage (July and August or substitute September in some cases) divided by the number of days in the months. On weekdays in the summer it is likely that the so-called base use is not large enough to meet demand. Summer use, therefore, is not actually allocated all the gas that it requires, leaving more gas treated as "remaining gas costs" and allocated more intensively to peak users.

Mr. Harrison claimed that if base use were defined as the amount needed to meet weekday load, then the model would show higher base use for commercial and industrial customers and lower heat factors for this group (transcript). This presumably would reduce their allocators for remaining gas use. Whether this actually reduced their allocation of remaining gas would depend on a number of factors. The amount of gas defined as baseload would increase and the amount defined as "remaining" would decrease. Both the base and the design day allocators would probably change. It is not clear that the general service design day allocators would actually decrease. The pattern of lower use on weekends and higher use on weekdays would be expected to hold during the winter as well as during the summer. If a very cold day occurred on a weekday, the base use in the winter would be higher than in Mr. Harrison's computations, raising the commercial and industrial design days. In summary, defining base use incorrectly creates a number of problems. The Department should require that in the Company's compliance filing base use be defined as the minimum MDQ that is necessary to meet summer load, and all of the resulting changes to allocators and to the definition of remaining gas costs also made. This method of computing base use should also be employed in the Company's CGAC filings on a going forward basis.

[39] It is unclear how the weather normalization method will compare in the future to what was filed in the cost allocation study. For instance, the basic weather normalization of class use depends on the Company's billing cycles in each month, on when customers were billed, and on the assumption that customers in each

For instance, this case used12 months of data with smoothed peaks, while the Capacity Assignment itself will use 18 months of data and actual peaks. There would be inconsistency between the proposed CGAC design day and the Capacity Assignment design day allocator. Moreover, the computation for Capacity Release would be different from that used in the CGAC, as it will be based on customer specific hourly load, whereas the other computations will be based on class monthly loads. AG-RR-45.

For all of these reasons, the Department should reject proposed use of the design day-based allocator for CGAC costs.

B. The Company's Marginal Cost Studies are Flawed

Mr. Harrison's developed the marginal cost studies used in the Company's proposed rate design for both gas and electric rates. The filed marginal cost studies do not produce reliable estimates of marginal costs. Mr. Harrison admitted that he "had a great deal of difficulty quantifying figures for the company" and he went to "…extraordinary measures to get estimates," using "smoothed data." (Tr.5, p. 607) While this particular comment was made during discussion of the electric marginal cost study, it is clear that smoothed data was also utilized in the gas cost of service study. Exh. FGE-JLH- _(Electric MCS). Mr. Harrison did not even use correct Handy-Whitman data to represent costs by account, but simply used on particular escalation series. To estimate the marginal cost of gas investment as a function of degree day, Mr. Harrison sometimes used regression coefficients that differed dramatically from actual investment over time compared to load growth. This lack of concern for accuracy and consistency renders the studies unreliable. The Department should not rely on either the gas or

billing cycle are identical.

the electric marginal costs studies in setting the rates in this case. The Company should be required to develop more reliable estimates of marginal costs before rates may be set for any extended period of time using marginal costs.

C. The Company's Tariffs Should Be Revised Because They Do Not Comply with Department Regulations

The Company's tariffs are deficient in several respects.[40] The CGA tariff lacks a set of clear and comprehensive definitions; it is impossible to determine how the CGA is computed for any period based on the language of the tariff. Company witness Karen Asbury readily admitted that formulae are missing from both the CGA tariff and from the Company's Terms and Conditions tariff that contains the method for determining capacity allocations for customers migrating from sales to transportation service. Tr.6, pp. 721 and 723.

Department regulations require that:

> ". . . Tariffs and schedules shall show plainly all requisite detail fully to explain the basis of all charges to be made and all rules and regulations governing the same . . . . Schedules relating to gas, electric light and water companies shall show not only the price or unit upon which based, but any and all meter rentals, service charges, basis for determining demand, discounts, and other detail necessary for a complete understanding of the charges contemplated."

220 CMR 5.02 3(b). The Company's tariffs should be redrafted to provide the necessary detail contemplated by the Department's regulations.

The Company's tariffs contravene the intent of the Department's regulations that tariffs

[40] Fitchburg's tariffs have been developed from the model used in the unbundling efforts; for the most part all the LDC's tariffs suffer from the same deficiencies. The Department should work with all LDC's to tighten tariff language as part of either a generic proceeding or on a case by case basis using any changes here as the minimum for all LDCs, recognizing that each company may have different Department approved methods for calculating various CGA and capacity release components that need to be incorporated in individual company tariffs.

fully explain the basis for all charges and the Company should not be allowed to continue to leave significant details out of its tariffs–details that are critical to the understanding of how charges are determined. The lack of detail not only hinders customers in their understanding of their charges, but also hinders the Department's review of CGA calculations. As discussed above, the Company is planning to apply a different method in computing its CGA than its witness proposes–without the need to revise its CGA tariff. The Department should not risk allowing of any utility to slip through what may be a significant rate change in a proceeding that does not require an investigation or hearings. The Department should require Fitchburg, as part of its compliance filing, to file both CGA and terms and conditions tariffs that clearly define all terms used in the tariffs and identify and fully explain all formulae used to determine CGA charges and capacity costs allocated to eligible migrating customers.

The Company has proposed some changes to its current CGAC tariff, M.D.T.E. No. 83, but no changes are proposed for its terms and conditions. See Exh. AG-7-29, pp. 2-81 (current terms and conditions). The CGAC proposal revises language to implement the proposed design day allocation for "Remaining Demand" costs, in place of the proportional responsibility allocator now used. See Exh. FGE-KMA-1, Sched.-1 (Gas), redlined Cost of Gas Adjustment Clause Tariff, MDTE No. 117, §6.03(1)(a) ii, §6.03(1)(c) ii, §6.05 (Definitions), and §6.06(1) (Gas Adjustment Factor Formulae–Peak and Off Peak). The proposed formulae changes simply replace the PR (proportional responsibility) term with the DD(design day) term. The formulae continue to refer to §6.05 (Definitions) for an understanding of the Design Day Allocator (DD). Section 6.05 defines the Design Day Allocator term as "percentage allocator for capacity charges as calculated in each CGA filing." More clarity is needed for this to be a meaningful and useful document.

Fitchburg routinely provides somewhat detailed narrative support with each CGA filing explaining how calculations are performed. Exh. AG-7-8. The Department should require that the Company incorporate this level of definition into its CGAC tariff and use it as a model to rewrite its terms and conditions in order to expand the understanding of how mandatory capacity assignment allocations are made. As part of enhancing the explanatory aspect of the tariffs, the Company should also review and improve the "Definition" sections of both the CGAC and terms and conditions tariffs. Definitions should be tightened up so that they are meaningful, and not dead-ends similar to the proposed Design Day Allocator definition.

D. The Department Should Not Apply A PBR Inflation Factor To Production-Related Base Rate Components Recovered In The CGA

As part of the unbundling process undertaken by the Company in its last gas rate case, DTE 98-51, a portion of costs[41] were moved from the distribution revenue requirement to the CGA, where these costs are recovered from sales customers. The Department set the amount of these costs to be recovered in both the base rate and CGA components. The amount is fixed until the Company's next rate case. For purposes of the CGA, the amount of production costs deemed recoverable through the CGA is reconciled to the actual cost level approved in the Company's most recent rate case. The Company currently recovers only the amount of these costs that was established in its last base rate case (DTE 98-51). The reconciliation occurs annually as part of the Company's peak season CGA filing. Tr.7, p. 823.

The Company seeks approval to eliminate the annual true-up once the amount of CGA recoverable production related costs is determined in this proceeding. Instead, the Company

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[41] The Company categorizes these costs as Local Production and Storage Costs ("LPLNG"), Dispatch, Acquisition and FERC Proceedings Costs ("DAFP") and Production Related Overhead ("PRO"). Exh. FGE-KMA-1, pp. 13-14.

asks, in conjunction with is performance-based ratemaking ("PBR") proposal in another docket, to roll any existing under- or over-collection balances for these items into the CGA and begin to apply the PBR factor (inflation adjusted by the predetermined offset) to these costs. Exh. FGE-KMA-1, pp. 14-15. Tr. pp. 819-822. The Company's only support for the proposed change is "consistency" with the proposed treatment of the corresponding costs in base rates. *Id.*

This proposal must be rejected even if the Department approves a PBR for Fitchburg. The Company has not shown that these costs increase over time. In fact, the evidence indicates just the opposite, that these costs remain relatively the same from year to year. Exh. AG 7-24. Ms. Asbury confirms this by stating, "my review of the proposed numbers based on the 2001 test year were very similar to the 1997 levels." Tr.7, p. 824. Furthermore, these costs should decrease when there is significant migration to competitive suppliers. To the extent that costs in the CGA do not decrease when there is migration, there is the potential for cost shifting and the creation of stranded costs.

The Department has determined that certain costs should be collected through the CGA that were formerly collected through base rates, in an effort to reflect more accurately gas costs in a competitive environment (see DTE 98-32 and DTE98-51). These costs are base rate costs; the appropriate forum for determining the reasonable level of the costs is through a rate case where the propriety of the expenditures is adjudicated. The fact that a portion of the costs is recovered through an automatic adjustment clause mechanism, the CGAC, allowing dollar for dollar recovery, benefits the Company by guaranteeing full recovery of the approved costs. To get guaranteed recovery plus inflation increases every year would be unreasonable, particularly when the record shows that there is little if any annual increase in this category of costs.[42] The Department has addressed this very issue; it did not allow Boston Gas to apply its PBR factor to similar costs[43] in its CGA. *Boston Gas Company*, DPU 97-92, p. 16 (1997). There is no reason for the Department to depart from precedent here.

E. The Department Should Not Complicate The CGAC By Adjusting Bad Debt Recovery By Actual Write-offs

Currently the Company recovers its bad debt expense allowance through distribution rates and the CGA based on a ratio established in the Company's last rate case. During the year, the CGA bad debt component is reconciled to actual bad debt write offs using the ratio set in the last rate case. Tr. pp. 1811-12. The Company proposes to fix the Bad Debt recovery percentage rate in this case and determine the amount that will be recovered through its base rates. The Company proposes to vary the Bad Debt allowance for gas costs recovered through the CGA based on the actual write offs of CGA amounts. Tr. pp.1795-1796. The Company claims that its proposal should be allowed because it can track write offs separately for distribution and CGA components and gas costs are volatile. FGE-MHC-1, p. 45. Tr. pp. 756-757, and 1796.

The Company's request contradicts precedent. It would make CGA filings more

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[42] The majority of these costs are plant related (depreciation, return and taxes) and will decline as the depreciation recovery reduces the net plant which reduces the return requirement. Expenses include those booked to the category summarized on page 45 of the Company's Annual Return to the Department. According to the Company's returns for the years 1999 and 2001, there was a decrease of almost 20% during that time: the1999 expense was $462,759 and the 2001 expense was $372,830 (excluding gas costs). These amounts correspond to the cost of service amounts included in Exhibit FGE-JLH-1, Schedule JLH-5-1, page 9-1, line 14 (the amount allocated to the CGA is seen in AG-7-12--CGA Cost of Service Study, page 9-1, line 14 and the amount allocated to distribution rates is seen in AG-7-11, page 9-1, line 14).

[43] Boston Gas sought to apply the PBR factor to its local production and storage costs included in the CGA, costs that are analogous to only the LPLNG component of Fitchburg's more expensive category of "production base-rate components" for which the Company seeks permission to adjust annually under its proposed PBR.

complex, and would provide the Company with guaranteed recovery of cost that is substantially within the Company's control. The proposed change requires that the Company not only record the accounts receivable entry for each bill by CGA and distribution amounts, but also separately track partial payments in an appropriate manner, as well as allocate[44] between CGA and distribution any recoveries of previously written-off amounts. If the full range of allocations is not specified, payments and recoveries may be mis-allocated. The Company would be naturally biased to allocating payments and recoveries to the distribution component and less to the CGA due to the direct reduction of the CGA from allocation of these amounts to the CGA. The necessary complexity of implementing not only the payment and recovery allocations, but also the added administrative burden of reviewing and determining the propriety of the allocations and related costs as part of the CGA process, outweighs any benefit that may be derived from more accurately accounting for gas price volatility. In addition, the dollar for dollar recovery of CGA bad debt costs inhibits the Company's incentive to aggressively lower the level of uncollectible accounts.

If, despite the above arguments the Department approves the Company's proposal, the allocation rules discussed above need to be incorporated in the Company's CGA tariff.

Similarly, the company proposes to remove from the distribution cost of service an allocation of default service and standard offer service bad debt expense.[45] The allocated amounts would be recovered as part of the Company's standard offer and default service

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[44] Mr. Collin testified that the Company is unable to track recoveries by bill component, therefore an allocation rule is required. Tr.14, pp. 1737-8.

[45] In the Company's cost of service study, a component of bad debt has been allocated to internal transmission. Rules must also be applied for allocation to internal transmission if the Department approves such unbundling of bad debt cost.

charges. The recovery and reconciliation process for the bad debts related to Standard Offer and Default service parallels that proposed for the CGA related bad debt cost recovery. Exh. FGE-MHC-1, pp. 48-49. Before such a proposal is implemented, the Company must have in place specific allocation methods to appropriately allocate partial payments and recoveries.

F. The Department Should Amortize The Farm Discount Over The Life Of Any PBR Plan.

If the Department adopts a PBR Plan for the Company, it should amortize the remaining balance for the farm discount over the life of that Plan. *Berkshire Gas Company*, D.T.E 01-56, p. 36 (2002).

G. Default Service Procurement Costs

During the course of these proceedings, information became available indicating that the Company's most recent default service procurement had been made through an internet exchange platform rather than through a traditional RFP process.[46] Furthermore, Company witness Collin testified that the operator of the exchange, Entermetrix, was partially owned by Unitil, Fitchburg's parent corporation at the time of the procurements and that Enermetrix recovers its administrative costs through the imposition of a fee on all kilowatt-hours sold through its exchange. Tr. pp. 1113-1116.

The Department's default service procurement policy has been guided by several principals, one of which is "...default service prices should be market based, be procured through reasonable business practices..." *Investigation by the Department of Telecommunications and Energy on its own Motion into the Pricing and Procurement of Default Service Pursuant to G.L.*

[46] WMECo stated in comments filed in DTE 02-40, that Fitchburg's customers were paying administrative costs associated with the procurement of default service due to use of Enermetrix. Western Massachusetts Electric Company comments DTE 02-40, p. 3, dated August 9, 2002.

c. 164, §§ 1B(d), DTE 99-60-A (2000). The Department has authorized Distribution companies to procure default service through competitive solicitations, specifically utilizing the RFP process.

Only the current and prior default service procurements by the Company have not been the result a traditional RFP process. Fitchburg has committed a serious error–it procured the supply through the use of an related company that profited from the transactions. The Company did not seek Department approval to enter into a less than arm's length transaction. Affiliate transactions must be shown to be no greater than the market price for the service provided. 220 CMR 12.04 (3). The Company has not provided any analysis showing the fees charged by Enermetrix are not greater than what another such provider of these services would charge or that the fees are less than the costs that the Company would have incurred as part of an RFP procurement, or that the administrative costs of the last two default service procurements were less because Enermetrix services were used.

The Company's errors are serious and require remediation. The Department's affiliate transaction regulations provide that the Department may assess civil penalties of up to $1,000,000 after holding a public hearing. Under this provision the Department is able to order the Company refund to Default Service customers the amount of the Enermetrix fees of $0.0002/kWh for the first procurement and $0.000275/kWh for residential and small C&I load and $0.0003/kWh for medium and large C&I load. RR AG-34. The refund should begin immediately in order to return the fees to the customers that paid them.

X. CONCLUSION

For these reasons, the Attorney General submits that the Department should reject the Company's proposed new rates and tariffs, or in the alternative, adopt the Attorney General's pro forma adjustments.

Respectfully submited,

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